Exhibit 19

Fortieth Annual Report on the Electric Property of PREPA, dated June 2013

FORTIETH ANNUAL REPORT

ON THE ELECTRIC PROPERTY

of the

PUERTO RICO ELECTRIC POWER AUTHORITY

SAN JUAN, PUERTO RICO

UNDER TERMS OF TRUST AGREEMENT

Dated as of January 1, 1974, as amended,

to

U.S. BANK TRUST NATIONAL ASSOCIATION

TRUSTEE

JUNE 2013

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April 4, 2014

Puerto Rico Electric Power Authority,
San Juan, Puerto Rico 00936 and
U.S. Bank Trust National Association
New York, NY 10005, Trustee under the Trust
Agreement, Dated as of January 1, 1974, as amended

Gentlemen:

We submit herewith our Fortieth Annual Report (for fiscal year 2013) as required of the Consulting Engineers, URS Corporation, under the terms of Section 706 of Article VII of the Trust Agreement governing the Puerto Rico Electric Power Authority's Power Revenue Bonds.

Very truly yours,

George W. Romano Jr.

George W. Romano Jr.
Consulting Manager

GWR

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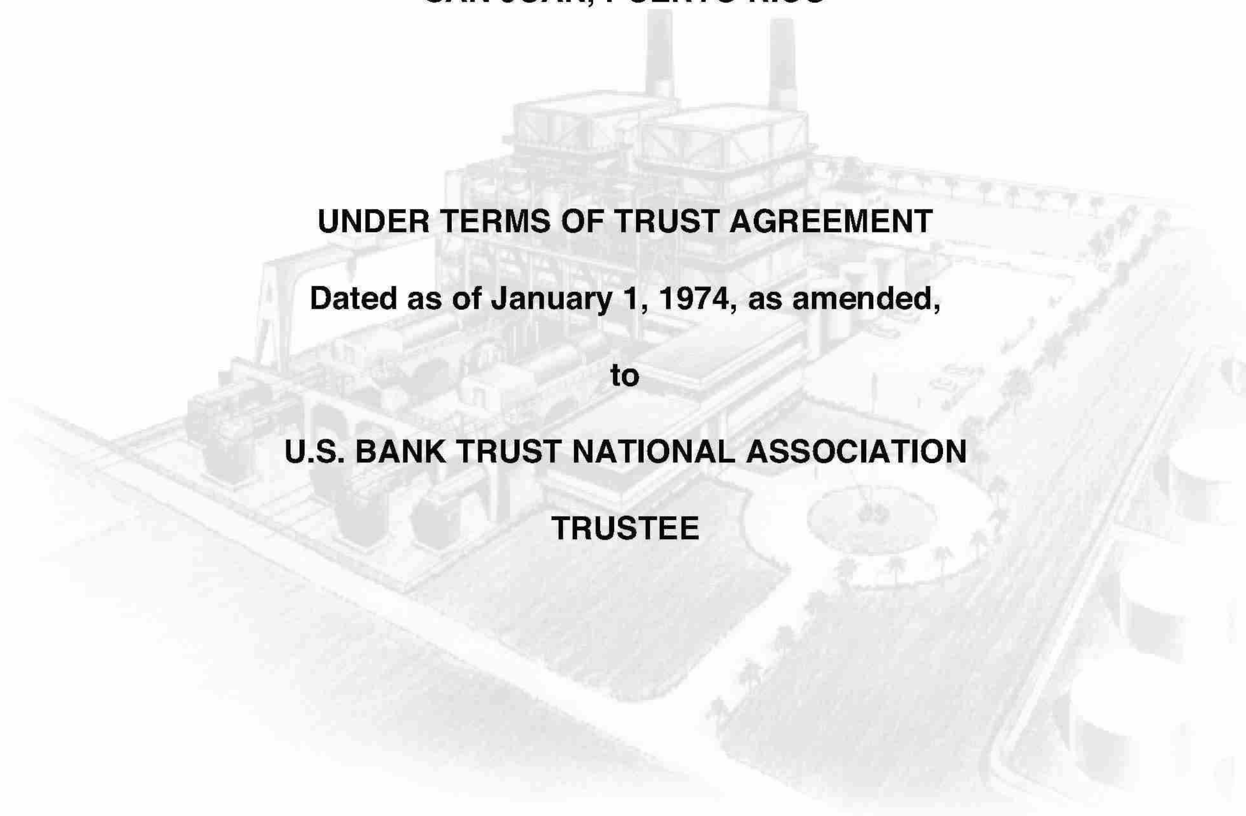
FORTIETH ANNUAL REPORT

ON THE ELECTRIC PROPERTY

of the

PUERTO RICO ELECTRIC POWER AUTHORITY

SAN JUAN, PUERTO RICO



UNDER TERMS OF TRUST AGREEMENT

Dated as of January 1, 1974, as amended,

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EXECUTIVE SUMMARY

This report is the 40th Annual Report by the Consulting Engineers in compliance with the 1974 Trust Agreement. The report is based on the Consulting Engineer's inspections, interviews and review of relevant data pertaining to the operation of the Puerto Rico Electric Power Authority electric System during the fiscal year 2013, ending June 30, 2013.

The Authority's reported total energy sales in fiscal year 2013 were 0.6% more than the previous year, but still 7.0% less than in fiscal year 2008. During the past fiscal year energy sales increased in the residential and commercial sectors and declined in industrial. The decline in the industrial sector was its seventh consecutive year and reflected the continuing impact of the recession in Puerto Rico. The Authority's Current Forecast for fiscal years 2014 through 2018 predicts a 1.3% growth in total energy sales for fiscal year 2014, with an average annual growth rate of 1.2% in fiscal years 2014 through 2018. The DOE Energy Information Agency forecasts the energy sales growth rate for mainland utilities during the same period will be 1.1%. Consistent with the interim-period forecast, the predicted slow growth of peak demand indicates the historic peak set in fiscal year 2006 will not be reached during the forecast period.

In fiscal year 2013 the Authority's electric sales revenues fell by 4.2% over the previous year as a result of the total cost of fuel declining 10.3% and purchased power increasing by 10.5% from the previous year. In fiscal year 2013 the Authority's net generation declined by 5.4%, while its average cost of fuel per equivalent barrel dropped 6.1%, aided by the lower cost of the natural gas burned at its Costa Sur plant. The total cost of fuel is forecasted to decline 17.6% in fiscal year 2014 from 2013, with purchased power costs increasing 6.6%. Total electric sales revenues, including theft recoveries, are projected to decline by 7.4% from fiscal year 2013 to 2014.

Net revenues, as defined by the 1974 Agreement, in fiscal year 2013 increased by 13.8% over the previous year as total current expenses fell by 6.6%, while total revenues were down 4.0%. The Authority forecasts its total revenues will decline by 6.8% in fiscal year 2014 from the results of fiscal year 2013; total revenues through fiscal year 2018 are projected to remain little changed from the fiscal year 2014 level. During the five-year forecast period through fiscal year 2018, the Authority projects its current expenses will also remain relatively stable as lower costs of fuel are offset by increased costs of purchased power. The resulting net revenues are forecasted to increase by 9.5% in fiscal year 2014 over 2013. In fiscal years 2015 through 2018 the net revenues are projected to increase 3.6%, drop 0.1%, and then increase 2.2% and 1.0%, respectively.

With the forecasted net revenues and the projected annual debt service through fiscal year 2018 in the Authority's budget used for this report, the projected debt service ratio based on the 1974 Agreement debt will range from 1.34 to 1.42 in the five fiscal years ending 2018. The budgeted financings may incur higher interest rates than forecasted and the ability to capitalize interest may be constrained as well. Both of these would increase the Authority's projected principal and interest requirements in the intermediate term, thereby lowering the forecasted debt service coverage ratio.

The largest operational issue facing the Authority is complying with the EPA hazardous air pollutant regulations by 2015. The Authority's plan to dramatically switch from fuel oil to natural gas was endorsed by the island's major stakeholders in a Commonwealth government convened public/private sector committee during fiscal year 2012. The committee identified alternative plans, but did not recommend a specific method for implementing the large increase in natural gas supply for the island. In the face of strong local opposition, projected cost escalations and regulatory uncertainty, during fiscal year 2012 the Authority stopped work on the proposed 92 mile pipeline from the south coast to three plant sites in the north. The Authority's current approach to expand the supply of natural gas on the island has been an offshore gasification facility for LNG deliveries near its Aguirre power complex on the southeast coast. The proposed Aguirre Offshore Gas Port (AOGP) will be a floating facility to receive and gasify LNG shipments. The Authority plans that the AOGP will be installed by a vendor under a long term agreement and the Authority has continued with the coordi-

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nated air permit effort with that vendor for both the AOGP scope and the Aguirre plants. The proposed permitting schedule would enable gas to be available for the Aguirre plant by the MATS compliance date of April 2015, with no margin for unanticipated delays.

During fiscal year 2013 the Authority continued its due diligence on the contractual structure of the gas supply infrastructure and was evaluating alternative supply arrangements for natural gas to the north of the island. The Authority is evaluating the structure of the LNG commodity supply agreements, which would be separate from the infrastructure development. The Authority plans to select the bases for establishing the development of the natural gas infrastructure and fuel supply during fiscal year 2014. These will lead to qualifying bidders and soliciting proposals by the end of that fiscal year.

Based on projected fuel costs, the Authority's initiative to expand gas firing at its generating plants to meet environmental regulations will also lower the Authority's cost of fuel, thereby benefitting the economy of Puerto Rico. During fiscal year 2013 the Authority operated Costa Sur Units 5 & 6, each a 410 MW unit, with natural gas providing most of the fuel for those units. The power generated from natural gas in these units accounted for 10.8% of the total power for the System; adding the power from the EcoEléctrica cogeneration plant put the total gas fired generation at almost 28% during fiscal year 2013. The Costa Sur units were the first steam units to be converted for dual fuel firing (burn oil and/or gas) because they are located adjacent to EcoEléctrica's LNG facility, which supplied the fuel under a short term contract that is scheduled to be renegotiated in fiscal year 2014.

The Capital Improvement Program (CIP) through fiscal year 2018 includes budgets to complete the dual fuel conversion work at the steam-electric units in accordance with plans for compliance with the EPA emission criteria, as well as the San Juan combined cycle units. By the end of fiscal year 2013 the Authority had performed much of the conversion work at various units during scheduled outages, and had completed the full scope for the two large units at Costa Sur. The next priorities are its two largest steam units at the Aguirre plant. Four steam units in the San Juan metropolitan area will be converted after the schedule for gas deliveries has been established. With sufficient fuel being available the Authority plans to add gas firing capability to the Authority's two most efficient units, San Juan Units 5 & 6, which are combined cycle units presently burning high cost distillate fuel.

Expenditures on capital improvement program projects during fiscal year 2013 were $327.7 million, which was 9.2% over budget; it was, however, 6.7% less than during the preceding fiscal year. The Authority has developed a lean capital expenditure plan for the five fiscal years through 2018, with plans to hold capital expenditures to an annual average of $310 million in that span. These budgets do not include construction of the natural gas supply infrastructure discussed above; the Authority plans to establish the funding structure for this work utilizing third party participants.

Fiscal year 2013 was the first during which renewable energy sources contributed meaningful amounts of the energy transmitted and distributed within the System; the Authority purchased energy principally from four renewable energy projects—an additional small wind turbine provided power occasionally. Together these projects produced 0.7% of the total System power. At the end of fiscal year 2013 the Authority had signed a total of more than 60 Agreements to Purchase Power from proposed renewable energy projects with a total capacity of approximately 1,660 MW. In the past fiscal year the Authority began renegotiating its agreements with many renewable energy project developers to lower their energy costs to the Authority and incorporate the minimum technical requirements that were revised in 2012 after many agreements had been signed. This has been an ongoing process that applies to all new projects as well. In fiscal year 2014 the Authority plans to perform a more refined analysis to identify the maximum generation from projected renewable energy resources that can be accommodated by the System. The Authority has forecasted that renewable energy projects will contribute 4.7% of the System power by fiscal year 2015 and stabilize at that level through 2018.

The Authority's System performed reasonably well during fiscal year 2013. The equivalent availability of the Authority's production plant at the end of fiscal year 2013 was 77%, the same level as one year earlier. The availability of the steam electric units in the past year was constrained by the continued program of overhauls and

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gas conversion work at the Authority's largest units. In addition, the Authority adopted a policy to minimize premium work time on scheduled outages to reduce its costs; extending the duration of the outages also reduced availability. The generating efficiency of the Authority's thermal plants in 2013 matched the average of the preceding three years. The reliability of electric service to the Authority's clients in fiscal year 2013, as measured by interruptions, consistently bettered their goals of less frequent and shorter interruptions.

Since 2000 and 2002 the Authority has utilized two private cogeneration facilities for fuel diversity, natural gas and coal, respectively; these sources also provide cost stabilization for a portion of the System's generation resources. During fiscal year 2013 these two plants produced approximately 34% of the System power and demonstrated reliable operation.

The Authority's total credits and costs to the Commonwealth for Contributions in Lieu of Taxes (CILT) and Other (comprised of three subsidies and an energy credit) were $180.6 million in fiscal year 2013, or 25% of the Authority's net revenues for the fiscal year, using the 1974 Agreement accounting. The Authority's fiscal year 2013 CILT credits (which apply to the municipalities) were well short of its actual obligations for that fiscal year, consequently the unpaid balance will be paid over the next three years. CILT credits during fiscal year 2013 included installment payments on unpaid CILT obligations from fiscal years 2010, 2011 and 2012. At the end of fiscal year 2013, the outstanding deferred CILT balance totaled $323.6 million. Recent legislation excludes municipal power consumption for money raising activities from the CILT amount. The Authority has factored this reduction into projected CILT obligations, which are structured to avoid increasing the accumulated deferred CILT balance. In addition to CILT, which benefits the municipalities, the Authority also incurred costs of $54.4 million for certain Commonwealth subsidies during the fiscal year and for the amortization of the outstanding line of credit used in the 2004 settlement of the lawsuit by the municipalities.

The 1974 Agreement obliges the Consulting Engineers to make specific assessments of the Authority's operations and make recommendations for deposits into certain Funds established under the 1974 Agreement. These are discussed in depth in the report and summarized below:

In the opinion of the Consulting Engineers, the properties of the System are in good repair and sound operating condition.

The Consulting Engineers believes the Authority will receive sufficient revenues in fiscal year 2014 with the existing rates to cover current expenses, to make all required deposits in accordance with the 1974 Agreement's dictates and to exceed its 120% debt service coverage requirement. Based on the outstanding debt at the end of fiscal year 2013, the debt service coverage was 138% in fiscal year 2013 and is forecasted to be 141% in fiscal year 2014, prior to adjustment for planned financings during fiscal year 2014.

The Consulting Engineers reviewed and approved the Authority's Annual Budget of Current Expenses and Capital Expenditures for fiscal year 2014, which was adopted in May 2013. The budget for fiscal year 2014 includes the first year of the Authority's five year Capital Improvement Program. In fiscal year 2014 the Authority is projected to contribute 7.6% or $22.7 million in internally generated funds to capital expenditures. The Consulting Engineers continues to recommend the Authority should pursue as aggressively as practicable the goal of achieving and maintaining annual levels of internal funding above that last met in fiscal year 2010 when it was 16%.

The Reserve Maintenance Fund was last used in fiscal year 2008 as an interim source of funds for the recovery following the fire at the Palo Seco Steam Plant. The balance in this fund was $15.8 million at the end of fiscal year 2013. The Consulting Engineers recommends the Authority make no deposits to the Reserve Maintenance Fund during fiscal year 2014.

At the end of fiscal year 2013, the Self-insurance Fund's balance was $92.2 million. This fund was also last used in fiscal year 2008 to cover uninsured losses associated with the Palo Seco Steam Plant fires. Based on the current fund levels, the Consulting Engineers recommends the Authority need not deposit any moneys into the Self-insurance Fund.

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INTRODUCTION

This is the Fortieth Annual Report by the Puerto Rico Electric Power Authority's (Authority) Consulting Engineers, URS Corporation (Consulting Engineers), filed to comply with the provisions of Section 706 of Article VII of the Trust Agreement, dated as of January 1, 1974, as amended and supplemented, between the Authority and U.S. Bank Trust National Association, the successor Trustee for the 1974 Trust Agreement.

Act No. 83 of the Legislature of Puerto Rico, approved May 2, 1941, as amended, reenacted and supplemented (the "Authority Act"), created the Authority a body corporate and politic constituting a public corporation and governmental instrumentality of the Commonwealth of Puerto Rico. Hereinafter, we will refer to Act No. 83 of the Legislature of Puerto Rico, approved May 2, 1941, as amended, reenacted and supplemented as the Authority Act.

With the release of the 1947 Trust Indenture on June 9, 1996, the 1974 Trust Agreement, dated as of January 1, 1974, as amended and supplemented, became the sole document governing all of the Authority's long-term financings, with the exception of minor subordinated interim debt. Throughout this report we will refer to the 1974 Trust Agreement, dated as of January 1, 1974, as amended and supplemented, as the 1974 Agreement.

Section 706 of the 1974 Agreement provides the following:

> *It shall be the duty of the Consulting Engineers to prepare and file with the Authority and with the Trustee on or before the 1st day of November in each year a report setting forth their recommendations as to any necessary or advisable revisions of rates and charges and such other advices and recommendations as they may deem desirable. After...the release of the 1947 Indenture, it shall be the duty of the Consulting Engineers to include in such report their recommendations as to the amount that should be deposited monthly during the ensuing fiscal year to the credit of the Reserve Maintenance Fund for the purposes set forth in Section 512 of this Agreement, deposited during the ensuing fiscal year to the credit of the Self-insurance Fund for the purposes set forth in Section 512A of this Agreement, if any, and deposited during the ensuing fiscal year to the credit of the Capital Improvement Fund for the purposes set forth in Section 512B of this Agreement.*
>
> *The Authority further covenants that the Consulting Engineers shall at all times have free access to all properties of the System and every part thereof for the purposes of inspection and examination, and that its books, records and accounts may be examined by the Consulting Engineers at all reasonable times.*

This Annual Report is based, in part, upon our knowledge of the Authority's operations gained over the more than 65 years that we (Consulting Engineers and its antecedent companies) have been retained as Consulting Engineers. We were initially retained in accordance with the provisions of Section 704 of Article VII of the Authorizing Resolution, dated January 1, 1944, and subsequently in accordance with Section 704 of Article VII of the 1947 Trust Indenture from its inception until its release, a period of 53 years. We have also served as Consulting Engineers in accordance with Section 706 of Article VII of the 1974 Agreement since its inception.

Each year, in fulfilling our duties as Consulting Engineers, we visit and note the condition of all the steam production facilities a minimum of three times; all the remaining production facilities at least once each year; one-third of the approximately 380 distribution substations and transmission centers; and a representative cross-section of all additional property owned and operated by the Authority. We regularly review the Authority's various reports and records, meet with the Authority's management and staff to discuss present operations and future plans, and perform a number of analyses relying primarily on data and information provided by the Authority. We also participate in all regular bond issue financings undertaken by the Authority by assisting in the preparation of the Official Statements, by providing several signed Engineers Certificates, and by participating in most bond rating agency presentations.

SYSTEM DESCRIPTION

The Authority's System supplies virtually all of the electricity consumed in Puerto Rico and the smaller islands of Vieques and Culebra. In the past fiscal year the Authority generated approximately 66% of the electricity itself and purchased the remaining. The two largest sources were the cogenerators, EcoEléctrica, L.P. located in the Municipality of Peñuelas and AES-PR located in the Municipality of Guayama. Power from five new renewable energy projects contributed 0.7% of the island's electricity for the last year. During fiscal year 2013, which ended on June 30, 2013, the System served on average 1,485,150 clients.

The Commonwealth of Puerto Rico is the easternmost of the islands comprising the Greater Antilles and is approximately 110 miles in length and 35 miles north to south. Central mountain ranges with peaks as high as 4,390 feet extend the length of the island from east to west. Coastal lowlands formed by the erosion of the central mountains extend inwards on the north coast for 8 to 12 miles and for 3 to 8 miles in the south. The northern coastal lowlands are humid while those on the south side of the island are semi-arid. The island's population density is high; approximately 58% of the island's 3.65 million inhabitants live in the broader metropolitan area of San Juan; the next most populous urban areas are Ponce and Mayagüez, with 12% and 7% of the island's population, respectively. The rural population is approximately 6% of the total and resides in the numerous small towns located along the island's perimeter and in the remote mountainous interior. Data from the 2010 census show the population of Puerto Rico declined by 2.2% in the ten years since the previous census; this was the first observed decline in the island's population. Data collected since 2010 indicate the decline in the island's population has continued with an additional estimated loss of 1.9% through 2012. Taken together Puerto Rico's geography, climate, and the dispersion of its clients within the Commonwealth present the Authority with many challenges as it designs, builds, operates, and maintains its System. The Authority serves its clients in 26 districts through seven regional offices, each of which incorporates a technical office.

Puerto Rico is in the path of many of the tropical storms and hurricanes that cross the Greater Antilles during the hurricane season, which runs from June through November. The Authority's transmission and distribution systems, more than 90% of which are above ground, are particularly vulnerable to the high winds, torrential rains, and erosion that are associated with tropical storms and hurricanes. The last hurricane to drastically affect both the island's economy and the System, Hurricane Georges, struck the island on September 28, 1998.

An electric power system is made up of production, transmission, distribution, communication and ancillary facilities, not all of which are physically connected, operated as a single integrated whole. The flow of electricity within the system is maintained and controlled by a dispatch center. It is the responsibility of the dispatch center's operators to match the real-time supply of electricity with the simultaneous demand for it. In order to carry out their responsibilities the System's dispatchers are authorized to buy power to complement the System's own generation and to economically dispatch it based on System requirements.

The Authority's primary dispatch center, which is under the direction of the Director of Generation, is located at Monacillos, approximately seven miles south of metropolitan San Juan. A Supervisory Control and Data Acquisition (SCADA) system, an integral part of the dispatch center's control system, has the ability to control total load flow on the island and can remotely control many of the Authority's substations and all of the large generating units. A secondary dispatch center is located in Ponce; it is continuously available to assume control if the primary control center has problems. Both centers are fully staffed during System emergencies, coordinating all restoration efforts.

The three major components of the System are the Production Plant, the Transmission system, and the Distribution system. They account for approximately 86% of the $11.7 billion Plant-in-Service investment. Below is a brief description of each of these components.

The production plant's dependable generating capacity, to the nearest megawatt, is 4,878 MW comprised of 2,892 MW of steam-electric capacity, 846 MW of combustion-turbine capacity, 1,032 MW of combined-cycle capacity, 100 MW of hydroelectric capacity, and 8 MW of diesel capacity. The 2,892 MW of steam-electric capacity consists of 14 units at four sites: Palo Seco–602 MW (four units) and San Juan–400 MW (four units), both on the north side of the island; Aguirre–900 MW (two units) and Costa Sur–990 MW (four units), both on the south side of the island. The last reduction in the Authority's capacity and number of steam-electric units occurred at the end of fiscal year 2008 when Costa Sur Units 1 & 2, which had a combined capacity of 100 MW, were removed from service. While the Authority has additional older steam-electric plants, there are no present

plans to retire them, although the future use of certain older plants may be limited as part of the Authority's strategy to meet new air emission standards. The Authority's 1,032 MW of combined-cycle capacity is comprised of two units at the Aguirre complex with a capacity of 592 MW and two units located in the San Juan Station with a total capacity of 440 MW, which came into service during fiscal year 2009. The 846 MW of combustion-turbine capacity consists of 29 units at nine sites around the island, the three-unit 248 MW Cambalache Station being the largest. The 100 MW of hydroelectric capacity consists of 21 units at 11 sites around the island, the 25 MW Yauco No. 1 being the largest unit. The Authority has two diesel generators each with 3 MW of capacity on standby reserve on the island of Vieques. On the island of Culebra four diesel generators having a combined capacity of 2 MW provide standby reserve. The Authority also has a mobile 1 MW diesel unit on Culebra; it is not connected to the System and is not listed as standby reserve capacity.

During fiscal year 2009 ten units came into initial service and four simple cycle combustion turbines were retired; these changes are reflected in the data above. The two largest new units were San Juan Units 5 & 6 combined cycle units, each having a dependable capacity of 220 MW. At Mayagüez four 21 MW combustion turbines were retired and removed from the site and replaced by eight aero-derivative simple cycle combustion turbines. The replacement combustion turbines increased the available capacity at the Mayagüez station from 84 MW to 220 MW.

The Authority's Sabana Llana battery energy storage system was designed to provide up to 20 MW for power factor correction and reserve capacity, however, the battery system has not been available for service since fiscal year 2006. At the end of fiscal year 2013 the Authority was evaluating proposals for salvaging the facility's batteries.

To supplement its own capacity, the Authority purchases power from two cogenerators under the terms and conditions of Power Purchase Operating Agreements (PPOAs). The Authority is in the thirteenth year of a 22-year PPOA for 507 MW of gas-fired capacity from EcoEléctrica, L.P. and is in the tenth year of a 25-year PPOA for 454 MW of coal-fired capacity from AES-PR. The 961 MW of capacity provided by the cogenerators brings the total dependable capacity available to the Authority to 5,839 MW. (See *Appendix VIII, System Capability*.)

Since few projects were operating the prior year, fiscal year 2013 was the first year in which renewable energy projects provided a meaningful amount of power to the System, all were under 20 year PPOAs. The operating renewable sources were the Pattern wind farm in Santa Isabela with a nominal rating of 75 MW, Punta Lima wind farm in Naguabo with a nominal rating of 26 MW, the 1 MW wind turbine at the Bechara water treatment facility in San Juan, the AES Iluminia 20 MW solar farm in Guayama and the 2.1 MW Windmar solar farm near Ponce. Additional renewable projects are scheduled for completion and operations in fiscal year 2015. All of these renewable energy projects are intermittent sources of power because they rely on the availability of wind or sun light, consequently they are not considered reliable capacity.

The Authority's transmission system is an interconnected network of 230 kV, 115 kV, and 38 kV power lines that carry electrical power from the production plants to numerous distribution centers from where it is distributed to clients for consumption.

At the close of fiscal year 2013, the transmission system was comprised of 2,478 circuit miles of lines: 375 circuit miles of 230 kV lines, 727 circuit miles of 115 kV lines, and 1,376 circuit miles of 38 kV lines. Included in the transmission system totals are approximately 35 miles of underground 115 kV cable, 63 miles of underground 38 kV cable and 55 miles of 38 kV submarine cable. In addition to the high voltage lines, the transmission system includes transformers at the generating plant substations, transmission centers for interconnection of different voltage systems and switch yards and gear for connection or separation of portions of the transmission system operating at the same voltage. High voltage transformers installed in the Authority's transmission system and its production plants have a total transformer capacity of 19,207 MVA.

As of June 30, 2013, the Authority's distribution system consisted of approximately 31,550 circuit miles of distribution lines (with operating voltages ranging from 4.16 to 13.2 kV) and 333 substations (with a total installed capacity of 5,018 MVA). The distribution system has more than 1,800 circuit miles of underground lines. The Authority has 22 portable transformers with a total capacity of 349.6 MVA to substitute for existing transformers during maintenance or outages; similarly the Authority has two portable capacitor banks each rated at 18 MVAR. There are 813 privately owned substations (with a total installed capacity of 3,266 MVA). The distribution system also includes approximately 1,485,200 client meters.

SYSTEM'S OPERATIONS

PRODUCTION PLANT

The Authority continues its commitment to an ongoing, long-term program to extend the life and to maintain the high level of availability of its generating units. The program consists of three components: formal operator training, comprehensive preventative maintenance, and design modification. The formal operator training part of the program emphasizes safety, operating efficiency, and equipment integrity. The comprehensive preventative maintenance part of the program requires the Authority to remove all major generating units from service for maintenance at regularly scheduled intervals to ensure their reliability. These intervals are referred to as "scheduled outages" in the text of this Annual Report. A residual life assessment of critical components is an integral part of the Authority's preventative maintenance practices.

The design modification part of the program represents the Authority's commitment to improve the operation of its generating units by installing redesigned, improved components, or by undertaking conversions. Examples of design modifications include upgrades of the eight 50 MW combustion turbines with original equipment manufacturer (OEM) improvements and the completion of modifications enabling them to burn distillate or natural gas. During fiscal year 2012 the Authority began the design modification of Costa Sur Unit 6's boiler, burner, and control system to support full load gas firing. These modifications were completed in the first half of fiscal year 2013; similar modifications to Costa Sur Unit 5 were completed by the end of fiscal year 2013. The initial phase of the modification of the Aguirre Steam Units to enable them to burn natural gas was completed during fiscal year 2012. The installation of the remaining design modifications to the Aguirre Steam Electric units are scheduled to coincide with the availability of natural gas at the station. The Authority also plans dual fuel conversion at other steam electric units and the combined cycle units at the San Juan Station over the next several fiscal years.

Years ago the Authority also converted all of its "forced draft" thermal plant boilers to "balanced draft" operation. These modifications allow the equipment to be operated at design or increased capacity with greater operational efficiency and reliability. Among the Authority's current projects are those that aim to increase the efficiency of its steam turbines by improving the performance of the associated steam condenser. These projects have included: retubing condensers; replacing condenser vacuum equipment; replacing cooling water filtration systems, and improving condenser backwash capabilities. The Authority has installed continuous condenser cleaning systems on several units; vendor owned continuous condenser cleaning systems are operated on a pay-for-performance basis. Turbine efficiency is also being improved through the installation of high efficiency seals, through turbine control upgrades, and through the installation of redesigned turbine blades.

The Authority purchased asset management software for its production plant and high voltage electrical equipment during fiscal year 2010 to replace and expand the existing system which was becoming outmoded. Among the expected benefits of the new program will be the improvement of the availability of critical generation and the reliability of certain high voltage transmission assets. The program was fully implemented during the past fiscal year for the production plant assets. During fiscal year 2011 the Authority's engineers participated in factory acceptance tests (FAT) of components of an upgrade to their Energy Management System (EMS). After operating the new EMS in parallel with the existing system to demonstrate its capabilities and reliability the new EMS was placed in service during fiscal year 2013. Both of these programs are more fully described in the *Technological Systems Operations* section below.

We visit all the steam-electric production facilities a minimum of three times each year and all of the remaining production facilities at least once each year. We examine numerous operations reports and we regularly meet with the Authority's management and staff to discuss present operations and future plans.

In accordance with an agreement approved by the Secretary of the Puerto Rico Department of Labor, Puerto Rico's Jurisdictional Boiler Inspector has allowed the Authority to increase the interval between boiler certifications from 12 months, as normally required by Commonwealth law, to 18 months. Nevertheless, at the end of fiscal year 2013 the Jurisdictional Boiler Inspector had certified all of the Authority's boilers within the previous 12 months.

MAINTENANCE

Routine maintenance activities are performed during environmental outages and during planned major outages which have broader scopes of work. Significant production plant upgrades or design modifications are accomplished during major overhauls. The routine maintenance activities are charged against the plant's maintenance budget. As is com-

mon in the electric utility industry, expenditures associated with significant production plant upgrades and design modifications are capitalized rather than charged as a current maintenance expense. Typically these activities are performed during scheduled major outages, although occasionally the Authority installs capitalized components during a scheduled environmental outage. During scheduled outages the Authority also performs non-destructive testing (NDT) examinations of representative critical components to establish their condition and perform or schedule appropriate repair work. The scope of NDT examinations includes boiler pressure parts, power piping, steam turbine components, electrical generators, transformers, and switchgear.

The duration of an outage varies based on the scope of work, availability of personnel and material, and budgetary constraints. Where the Authority routinely used extended work hours and temporary workers from other plants to shorten the duration of an outage in the past, present budget constraints have forced the Authority to minimize premium work time. The Authority has judged the cost savings associated with extending an outage are cost effective given the good reliability of its plants and the comfortable reserve capacity margin it has over recent demand.

The Authority schedules their fourteen steam-electric generating units out of service for an environmental outage at intervals of twelve to eighteen months. During an environmental outage the boiler and other components are cleaned to meet the requirements of the Air Compliance Preventative Maintenance Schedule contained in the Authority's Consent Decree with the Environmental Protection Agency (EPA). The Authority may keep a unit in service up to an eighteen-month limit subject to the unit's compliance with the emissions criteria in the Consent Decree. Frequently the Authority will advance the start of an environmental outage to ensure that adequate capacity is available during a period of high demand or to avoid having several units out of service concurrently. The following paragraph describes some of the cleanings, inspections, and replacements that the Authority performs during an environmental outage.

At the start of an environmental outage slag is removed from the boiler and the water walls are cleaned. The superheater, reheater, air heater, and economizer areas are washed and inspected, as are the exhaust gas ducts and the stack. Air heater components; seals, baskets, casing, and sector plates are inspected and replaced as necessary. Ductwork is repaired. Hoppers are emptied and cleaned, expansion joints are inspected for corrosion and leakage. Fuel handling equipment is inspected, repaired, and recalibrated as necessary. The forced and induced draft fans and the gas recirculation fan are cleaned, noise and vibration levels monitored, adjustments made and repairs completed. Motors for fans and main boiler pumps are cleaned and inspected. Dampers are inspected and adjusted. The windbox, burners, combustion air instrumentation, combustion controls, and soot blowers are inspected; damaged or worn components are either repaired or replaced. Monitors for opacity, oxygen, and furnace pressure are cleaned, recalibrated, or as necessary replaced. Pumps, feedwater heaters, the deaerator, and associated valves are inspected. Lubricating oil systems are inspected. Power transformers are inspected and breakers tested and adjusted. If a pressurized part of the boiler has been replaced the boiler part will be pressure tested before the unit returns to service. Life extension inspections and NDT activities are completed on critical systems and components in preparation for future programmed outages.

In the discussions regarding the status of production units that follow, the narrative will note the duration of a unit's environmental outage and describe work completed during the outage, which is in addition to that routinely performed during an environmental outage.

All of the Authority's fourteen steam-electric generating units were in service during fiscal year 2013. Ten of the 14 steam-electric generating units that were in service during fiscal year 2013 either completed or began an environmental outage during the fiscal year. The other four steam electric units were scheduled to begin the Consent Decree mandated environmental outage in the first or second quarter of fiscal year 2014. At the end of fiscal year 2013 all 14 of the steam electric units had completed an environmental outage within the 18 months allowed in the Consent Decree with the EPA.

With few exceptions the Authority sequences scheduled outages so that the large steam electric units are available for service from May through November, the months of maximum demand and greatest risks of weather disturbances. This strategy seeks, to the extent possible, to maximize the availability of the System's capacity while maintaining compliance with the Consent Decree with the EPA.

Steam turbines are internally inspected every five-to-seven years. This work, which is typically scheduled for a period of three-to-five months duration,

includes opening the high-, intermediate- and/or low-pressure section of the steam turbine, turbine control valve inspection, generator testing and repair, the disassembling, repairing, or replacing of major components; the scope of work is more comprehensive than an "environmental outage". It is identified as a "major overhaul" in the descriptions of the status of production units that are discussed below. Major overhauls frequently include rehabilitation work on the boiler and balance of plant systems.

One exception to the scheduled interval between major overhauls is Palo Seco Unit 2, which has been in service more than ten years between major overhauls. The Authority completed the overhaul of the HP, IP, and LP turbines of the 85 MW unit in May 2002. During the reconditioning of each of the Palo Seco units following a major fire in December 2006 the Authority examined critical components of each unit and determined that an extensive overhaul of Unit 2 was not required. Given the anticipated low level of dispatch of this unit following the Authority's compliance plan for the MATS clean air emission standards discussed in the *Environmental* section the Authority has not scheduled a major overhaul of this unit, however environmental outages and targeted maintenance will continue. Palo Seco Unit 2 recorded an equivalent availability of 87% during fiscal year 2013.

Occasionally the scope of work performed during a major overhaul will cause the schedule to be extended beyond the three-to-five months required to complete the turbine work. These events are detailed in the unit descriptions that follow.

The Authority's remaining production plant also includes both simple cycle and combined-cycle combustion-turbines, and a number of relatively small hydroelectric plants.

The Authority schedules maintenance on its 39 combustion-turbines (29 operated in simple cycle configuration and ten operated in combined-cycle configuration) based upon the number of "equivalent fired hours" of operation as specified in manufacturers' manuals. The equivalent fired hours concept takes into account the wear and tear associated with starting up the units as well as other operating factors that reduce the actual number of hours that units can be run between inspections. Eighteen of the Authority's simple cycle combustion-turbines are 21 MW Frame 5 machines, located at seven sites throughout the island. During the 1990's the Authority improved the performance of these combustion turbines by upgrading them to model "PA" configuration. One of the benefits of the "PA" modernization is that the interval between certain inspections increased the equivalent fired hours as follows: fuel nozzles of these units are inspected every 1,125 equivalent fired hours or 2,250 equivalent fired hours for units with air atomization; combustion section inspections are conducted every 4,500 equivalent fired hours; and intermediate inspections are conducted every 9,000 equivalent fired hours. Compressor and power turbine sections are rebuilt during major overhauls, which are scheduled every 18,000 equivalent fired hours.

In 2004 the Authority began a program to replace certain components in 16 of its eighteen 21 MW combustion turbines. The program included the replacement of the ratchet and torque converter thereby improving starting reliability, the installation of a universal fuel system, turbine modifications, an upgrade of the turbine control system, and new digital controls for the exciter. The final combustion turbine in the program is scheduled for the upgrade in fiscal year 2014.

Lubricating oil analysis and other preventative maintenance and diagnostic tests are performed monthly.

Eight new FT8 aero-derivative simple cycle combustion turbines went into service at the Authority's Mayagüez plant during fiscal year 2009. These eight combustion turbines comprise four unit blocks. The combustion turbines are connected in opposed pairs, between each pair is a 55 MW generator. The four units are capable of 220 MW; they replace the four 21 MW combustion turbines that were previously sited at the Mayagüez plant. The new units will be inspected and maintained at the following intervals:

"A" Inspection the sooner of every 1,000 hours or annually, during which borescope inspections are performed and preventative maintenance completed under the direction of a technical advisor.

"B" Inspection performed every 12,500 hours is a hot section inspection of the combustors, the power turbine sections and the seals and bearings. The unit is disassembled and shipped to a shop for the inspection.

"C" Inspection performed at 25,000 hours includes the inspection and refurbishment of the combustion turbine's intermediate case, the bearing compartments, pumps, in addition to the components inspected during a "B" inspection.

"D" Inspection performed at 50,000 hours entails the shop inspection of all sections of the combustion tur-

bine and the refurbishment or replacement of worn components.

The three 82.5 MW Model GT 11N combustion-turbines power blocks at the Cambalache Combustion-Turbine Station are inspected and maintained in accordance with the schedule below:

Class "A" Inspection every 4,000 equivalent fired hours: the combustor, burners, and turbine blades are inspected; the duration of the inspection is approximately six days.

Class "B" Inspection every 8,000 equivalent fired hours: the instrumentation is recalibrated; the combustor, burners, and turbine blades are inspected; and the once-through steam generator (OTSG) is washed; the duration of the work is approximately six days.

Class "C" Inspection every 16,000 equivalent fired hours: the blades in the compressor section are replaced; the combustor is removed for inspection; the combustor liner is replaced; thermal tiles and holding rings are replaced; the turbine is opened; the first three rows of blades in the high-pressure section of the turbine are replaced; auxiliaries are inspected and repaired as necessary; the duration of the work is approximately 31 days. The removed combustor liner and turbine blades are refurbished for use during future outages.

The Authority completed the upgrade of the last of the Frame 7 combustion turbines at the Aguirre Combined Cycle Station to a modified Frame 7EA design during fiscal year 2007. The upgrade allowed the Authority to increase the number of equivalent fired hours a combustion turbine is in service between scheduled maintenance inspections to the hours cited below:

Combustion inspections during which burner nozzles, check valves, filters, and associated instrumentation are inspected are scheduled every 5,300 equivalent fired hours. Prior to the design upgrade combustion inspections were performed at 4,000 equivalent fired hours intervals. Combustion outages take less than a week.

Hot-gas-path inspections, during which the liner, the first stage turbine blades, rotor bearings, burners, etc., are inspected, are scheduled approximately every 15,900 equivalent fired hours. The turbine inspection ports are opened; turbine blades are replaced as dictated by the degree of blade corrosion. A hot-gas-path inspection is typically completed over an eight-week period.

Major overhauls, during which the turbine and compressor are opened and blades in the first stage of the turbine are replaced, are scheduled after 31,800 equivalent fired hours. In addition, reduction gears and other turbine components and auxiliaries are inspected and repaired. Duct sections, baffles, the exhaust stack, the generator, and other electrical equipment are also inspected and repaired. Filter media in the air intake system are also replaced at this time. A major overhaul is typically completed over a sixteen-week period.

The steam turbines of the Aguirre combined-cycle plant are maintained in accordance with the same guidelines as those followed for the 16 steam-electric turbines; however because their service is intermittent and most often at partial load the years between scheduled overhauls may exceed those of the steam-turbines. The service intervals for these two steam turbines are discussed in the *Aguirre Combined Cycle Plant* section below.

During October 2008 the Authority's two 220 MW combined-cycle units, San Juan Units 5 & 6, went into commercial service. Each unit is comprised of a single combustion turbine with a capacity of 160 MW and a steam turbine with a capacity of 60 MW. The Authority has signed a long term service agreement, LTSA, with the combustion turbine vendor of approximately eight years duration during which the vendor will be responsible for the maintenance of the combustion turbine generator and the steam turbine generator. The Authority will be responsible for the maintenance of the combined-cycle plant's auxiliaries. Combustion turbine inspections will be performed on the basis of equivalent service hours, ESH, as follows:

8,000 ESH – Modified Combustion Inspection – fuel nozzles, combustor baskets, transition pieces, turbine blades in rows 1, 2, 3, and 4, and turbine vane and ring segments in rows 1 and 2 will be replaced. Inspections of the inlet, compressor, turbine, and exhaust sections of the combustion turbine are completed.

16,000 ESH – Combustion Inspection – fuel nozzles, combustor baskets, transition pieces, turbine blades in rows 1, 2, 3, and 4, and turbine vane and ring segments in rows 1 and 2 will be inspected and replaced as necessary. Inspection of the inlet, compressor, turbine, and exhaust sections of the combustion turbine are performed.

24,000 ESH – Major Inspection of the combustion turbine is completed with inspection and replace-

ment of blades in the compressor section and in the turbine section.

San Juan Units 5 & 6 Steam Turbine Generator inspections will be performed on the following frequencies:

Steam Turbine Generator Valve Inspections will be performed every 18 months. The scope includes the cleaning, NDT, and adjustment of HP stop and control valves, reheat stop valves, and intercept valves.

Major Inspections of the steam turbine generator are performed every 50,000 ESH.

The Authority has significantly reduced the duration of unscheduled outages of some of its large generating units by maintaining an inventory of critical spare components. On a long-term basis this practice has contributed to the improvement of both unit and System availability. Refer to the *Spare Components* section below for a listing of the major spare components.

The hydroelectric generating units are inspected on an annual basis and opened every five years.

Maintenance expenditures outlined below include costs associated with the thermal plants as well as the hydroelectric generating plants. These costs do not include the cost of the new capitalized units of property, and therefore they do not completely reflect the Authority's total cost of maintaining its fixed assets. As shown in *Appendix III, Detail of Operating and Maintenance Expenses,* maintenance expenditures for the production plant, including the hydroelectric, for fiscal year 2013 totaled $102.2 million. While maintenance costs were under the budget, the actual expenditures of $71.7 million for operations of the production plant exceeded that budget and erased the potential savings. The Authority's budget for operation and maintenance of the production plant for fiscal year 2014 is 2.4% more than the actual expenses in fiscal year 2013. The total operation and maintenance budgets for fiscal years 2015 through 2018, respectively, decline 6.5%, increase 1.1%, increase 0.3% and are level for the last two fiscal years.

STATUS OF PRODUCTION UNITS

The statuses of the Authority's production units are described in the following sections based on their condition as of the week of June 30, 2013

The table below provides a brief profile of each unit (capacity data, age, annual heat rate, and annual equivalent availability). The annualized heat rate is a measure of a unit's operating efficiency, which can be affected by its level of dispatch and other factors, such as capacity limitations caused by out of service equipment or sub-systems. Since heat rate is measured in terms of required fuel heating value input to produce one kilowatt of power, better performance is indicated by a lower heat rate. During fiscal year 2013 the Authority's generation based on fossil fuels achieved a net heat rate of 10,696 Btu/kWh, which was very close to the average for the previous three years.

Annual equivalent availability is defined as the percentage of time a generating unit was available, at its rated capacity, for service in a rolling 12-month period. For this Annual Report that period was the fiscal year ended June 30, 2013. The equivalent availability of the Authority's production plant for fiscal year 2013 was 77%, which was consistent with the previous year. The system availability in the past fiscal year was constrained by the six month outage of Costa Sur Unit 5 for a major overhaul and gas conversion work. The Authority's policy to minimize premium work time for scheduled outages has extended the duration of these outages, which will also lower the equivalent availability.

The annual capacity factor of a generating unit is based on its total net generation over the last fiscal year divided by the maximum power it could have produced based on operating every hour of the year.

A summary of annual performance data for each unit is presented on the table to the right:

AUTHORITY'S PRODUCTION PLANT SUMMARY PERFORMANCE FISCAL YEAR 2013

	DEPENDABLE CAPACITY	INITIAL OPERATION	ANNUAL HEAT RATE	EQUIVALENT AVAILABILITY
STEAM PLANTS				
Aguirre Unit 1	450	1971	10,197	86%
Aguirre Unit 2	450	1971	11,003	91%
Aguirre Station			10,615	89%
Costa Sur Units 1 & 2 *Removed from service 4/30/08*				
Costa Sur Unit 3	85	1960	13,198	73%
Costa Sur Unit 4	85	1962	12,705	60%
Costa Sur Unit 5	410	1969	11,280	42%
Costa Sur Unit 6	410	1972	10,858	70%
Costa Sur Station			11,163	58%
Palo Seco Unit 1	85	1959	11,171	88%
Palo Seco Unit 2	85	1959	11,147	87%
Palo Seco Unit 3	216	1967	10,566	60%
Palo Seco Unit 4	216	1968	10,596	82%
Palo Seco Station			10,765	76%
San Juan Unit 7	100	1964	11,384	72%
San Juan Unit 8	100	1964	11,434	88%
San Juan Unit 9	100	1966	11,390	81%
San Juan Unit 10	100	1965	11,525	82%
San Juan Station (excl 5 & 6)			11,435	81%

	DEPENDABLE CAPACITY	INITIAL OPERATION	ANNUAL HEAT RATE	EQUIVALENT AVAILABILITY
COMBINED CYCLE UNITS				
Aguirre Combined Cycle Unit 1	296	1976		
Combustion Turbine 1-1	50		12,704	99%
Combustion Turbine 1-2	50		12,639	99%
Combustion Turbine 1-3	50		12,541	64%
Combustion Turbine 1-4	50		12,923	99%
Steam Turbine 1	96			64%
Aguirre Combined Cycle Unit 2	296	1975		
Combustion Turbine 2-1	50		12,470	98%
Combustion Turbine 2-2	50		12,685	93%
Combustion Turbine 2-3	50		13,017	99%
Combustion Turbine 2-4	50		12,738	91%
Steam Turbine 2	96			88%
Aguirre Combined Cycle Plant			10,582	87%

	DEPENDABLE CAPACITY	INITIAL OPERATION	ANNUAL HEAT RATE	EQUIVALENT AVAILABILITY
COMBINED CYCLE UNITS (continued)				
San Juan Unit 5	220	2008	7,959	
Combustion Turbine 5	160			79%
Steam Turbine 5	60			96%
San Juan Unit 6	220	2008	8,665	
Combustion Turbine 6	160			100%
Steam Turbine 6	60			50%
San Juan Combined Cycle Units			8,253	85%
COMBUSTION TURBINES				
Cambalache CT Power Blocks				
CCTP 1	82.5	1997	-	0%
CCTP 2	82.5	1997	12,208	90%
CCTP 3	82.5	1998	11,750	99%
Cambalache CTs			11,989	63%
Frame 5 GT Power Blocks				
9 Blocks of 2 GT's	378	1971-1973	15,583	88%
Mayagüez				
GT 1	55	2009	9,821	27%
GT 2	55	2009	10,625	99%
GT 3	55	2009	10,411	86%
GT 4	55	2009	10,039	99%
Mayagüez GTs			10,317	78%

	DEPENDABLE CAPACITY	INITIAL OPERATION	ANNUAL HEAT RATE	EQUIVALENT AVAILABILITY
THERMAL SYSTEM				
	4,770		**10,696**	**77%**

	DEPENDABLE CAPACITY	INITIAL OPERATION	ANNUAL SERVICE FACTOR	EQUIVALENT AVAILABILITY
HYDRO				
Total for 21 Hydro Units	100	1929 - 1953	10%	63%
DIESEL GENERATORS				
Total for 6 DG sets	8	1980 - 2006	0%	95%

Steam-Electric Production Plant

Total Generating Capacity 2,892 MW

The generating units within a steam-electric generating station are identified by acronyms in the following manner: Unit No. 1 in the Aguirre Steam Plant is introduced as ASP Unit No. 1; Unit No. 3 at Costa Sur Steam Plant is CSSP Unit No. 3, and so on. The narratives on the generating units in this section generally present information by paragraph in the following sequence:

The first paragraph provides historical and annualized operational data and summarizes the types and number of outages the unit experienced during the fiscal year. In this paragraph and in the following paragraphs turbine sections are identified in the following manner: high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP).

The second paragraph describes the number and types of scheduled outages (major overhaul, environmental outage, or maintenance outage) the unit experienced during the fiscal year. The work performed during maintenance outages is described if the outage was longer than 24 hours. However, if a unit was scheduled out of service repeatedly for the same reason, the cause of the maintenance outages and their resolution will be noted regardless of the brevity of the outage. The time assigned to scheduled reserve economic shutdown, in which the unit is available but excluded from dispatch, will also be noted.

The third paragraph describes the number of times and the duration of forced outages and unit limitations the unit experienced during the fiscal year. The cause of the outage or limitation and the action(s) taken to return the unit to full service is described when the forced outage or limitation was of more than 24 hours duration. Repeated outages or limitations attributed to the same cause are noted, despite being of less than 24 hours duration. The Authority tracks unit limitations as "equivalent outage hours" (EOH), which are a measure of the hours the unit's output was restricted below full capacity; for example, operating for 24 hours while the unit output is limited to 50% is equivalent to 12 hours of outage for the unit at full capacity.

The fourth paragraph notes the next scheduled outages for the unit that are planned for fiscal year 2014 or beyond, including the scheduled start of the unit's next major overhaul. The discussion addresses equipment and system replacements and upgrades that are included in the Capital Improvement Program (CIP).

The planned CIP expenditures for station services that impact a number of the station's units are included in the narrative of the station's first unit.

The federal air quality requirements that will restrict the Authority's use of residual oil are discussed in the *Environmental* section and are referred to as MATS, for mercury and air toxics standards. In this section references to the NPDES (national pollutant discharge elimination system) sections 316 (a) and (b) program apply to the Authority use of cooling water; these requirements are also addressed in the *Environmental* section

Aguirre Steam Plant

ASP Unit No. 1 (nominal 450 MW) was not in service on June 30, 2013, because it was in the middle of a scheduled environmental outage. During fiscal year 2013 the unit was scheduled from service five times; once for a programmed outage and four times for maintenance. Scheduled outages kept the unit from available status a total of 38 days in the past fiscal year. It was forced from service five times for a total of slightly more than nine days; each of the two longest of these outages was between three and three and a half days in duration. The unit accrued approximately three equivalent outage days, attributed to six different events over the course of the year. While in operation during the past fiscal year this unit generated an average net power of 270 MW. Unit 1 was in service 7,615 hours during the fiscal year and had an annual capacity factor of 52%.

During the past fiscal year the unit was scheduled from service four times for maintenance before it began an environmental outage on June 3, 2013; the start of the environmental outage was prompted by a fault in the motor drive of boiler feed pump (BFP) 1-2 earlier that day. Each of the first three maintenance outages was two days duration. The first in July involved repairs to reheater tube leaks, replacement of one of the boiler circulating water pumps (BCWP), inspecting the lube systems on all BCWPs, testing the burner management system (BMS), testing the breaker for the motor driven boiler feed pump (BFP) and rebalancing the induced draft fan (IDF) 1-2. The second outage addressed repairs to one of the superheater temperature control spray lines. In December the third outage was to install thermocouples in the superheat and reheat sections of the boiler to collect performance data for firing natural gas. The fourth maintenance outage took five days at the end of May to repair leaks in the generator hydrogen cooling system.

Unit 1 was forced from service for one day in September to repair a service breaker associated with the normal station service transformer (NSST) 1-A. A month later the unit was forced from service for three days to repair a leak in the generator's stator coolant; while those repairs were being performed a deaerator leak was repaired and the condenser gates were inspected and adjusted. In November the unit was forced out for a day to repair superheater tube leaks. During this outage the proper operation of the forced draft (FD) fans' control vanes was verified, and the BMS and NSST were inspected. An eight hour forced outage in June was caused by a fault in the motor drive of BFP 1-2; this outage was continued as the environmental outage discussed above. The unit had six episodes of limitations during the fiscal year. Three occurrences were caused by condenser tubes leak, which amounted to one equivalent outage day. An electrical ground fault caused five hours equivalent outage hours in February. In May, problems with fouling of the regenerative air pre-heater (APH) coupled with a generator hydrogen leak accounted for two days equivalent outage hours. This unit was not placed in economy shutdown at any time during fiscal year 2013.

The next major outage for Unit 1 is scheduled to begin in July 2014 and last 20 weeks, with its primary objective being the conversion of the boiler for firing natural gas, in addition to heavy oil. The previous major outage was completed in February 2012, during which the control systems were upgraded for dual fuel operation. During the upcoming major outage the scope of work will include an environmental outage plus boiler modifications to the convection section (superheat and reheat) headers and tubes to be compatible with gas firing. Other work will include repairs to thermal insulation, installation of new motor control center (MCC) and switchgear for the circulating water pumps.

The replacement of equipment and upgrades to systems during major overhauls are funded through the Capital Improvement Program, CIP. The CIP allocates a total of $23.6 million for the two Aguirre steam units in fiscal year 2014 and $41.8 million the following year; these amounts include environmental projects at the facility.

The Authority has a five year program to improve the quality and quantity of its plant water supply. The first phase included installing a reverse osmosis (RO), unit and adding a demineralized water storage tank. The second phase involves improvements to the water supply from PRASA in which two 2.5 million gallon retention ponds, filtration equipment and piping will be installed. Much of this scope is eligible for low cost financing from the Commonwealth. During the last year the Authority completed the refurbishment of one of the station's fuel storage tanks; work on the next tank will begin in fiscal year 2014. The replacement of the boiler structural steel is continuing on both units. The CIP has also budgeted for the requalification of the HP/IP turbine rotor and of the generator rotor that was removed during the overhaul that was completed in February 2012. The Authority will receive the replacement for the failed main power transformer at Aguirre during fiscal year 2014.

ASP Unit No. 2 (nominal 450 MW) was in service and capable of full output on June 30, 2013. During fiscal year 2013 the unit was scheduled from service nine times, these outages kept it from service for a total of more than 18 days; there were nine forced outages causing the unit to be out eleven days. The unit was in service for 8,046 hours during the fiscal year. During the past fiscal year Unit 2 generated an average net output of 286 MW and recorded an annual capacity factor of 55%.

The three outages for repairs to the main boiler feedwater control valve (FCV-1) accounted for more than half the year's scheduled outage hours. Two of these outages were for more than four days: in January the electrical to hydraulic actuator for the control valve was cleaned and refurbished; in May a leak in the control valve was repaired. In February during a two day outage the stem on FCV-1 was replaced. In August a two day outage was scheduled to repair leaks in the boiler feedwater piping and some boiler tubes. During the outage, maintenance was performed on the opacity meters, a burner isolation valve was replaced, a small steam line leak was repaired, the BMS was tested, and the motor was replaced on the motor driven boiler feed pump. Most of the balance of scheduled outage hours for this unit were for problems with the superheater tubes and steam cooled hangers. The troublesome steam cooled hangers will be replaced as part of the convection section redesign for the conversion to gas firing. Repairs to the superheater section were included in a two day outage in October and two outages in March totaling almost three days. In March a leak in the superheat temperature control spray water line was repaired in a one day outage.

The longest forced outage resulted from a breaker failure that tripped the unit from service; repairs were completed and the unit returned to service 34 hours following the trip. The three other outages were less

than half a day in duration. The Authority made repairs to the generator brush assembly during two brief forced outages, the longer of which was four hours in duration. At the onset of a transmission system event the Authority put the unit in reserve shutdown and returned it to service 20 hours later.

Unit 2's next overhaul is an extended environmental outage scheduled to begin in November 2013. In addition to the full scope of an environmental outage's cleaning, inspection and maintenance, the scope of work will include the repair of the pendant superheat supports, evaluation of the reheat elements and the replacement of sections of boiler steel. The low pressure feed water heaters will be examined for useful life. Thermal insulation will be repaired as necessary.

In fiscal year 2016 Unit 2 is scheduled for a major outage. During the overhaul the installation of gas piping, pressure reducing valve stations, and burners capable of firing natural gas will be completed to support full gas firing. A new turbine control system will be installed, as will a new automated voltage regulation (AVR) system. The HP/IP turbine rotors and the turbine control valve will be replaced and the stop valve inspected and refurbished. The generator stator will be rewedged and the generator's rotor will be rewound. The deaerator will be replaced, as will the gates at the water boxes of the auxiliary condenser. The pipe type high voltage underground cable will be refurbished.

Costa Sur Steam Plant

CSSP Unit No. 1 and CSSP Unit No. 2 (both nominally 50 MW) these two units, which entered service in the 1950s, were taken out of service in fiscal year 2004. During fiscal year 2008 the Authority's stopped reporting on the availability of these two units and identified systems within these units that provide service to one or more of the other Costa Sur units; these units no longer house or support components or systems that service the balance of the plant. In the past year the Authority solicited bids for the removal of these units. The bids confirmed that the cost to demolish these units will be difficult to fund in the current environment of budgetary constraints. The Authority has deferred awarding the demolition work for at least a year.

CSSP Unit No. 3 (nominal 85 MW) On June 30, 2013 this unit was in reserve shutdown for economy; it was available for service with its output limited to 65 MW due to chronic problems of boiler casing air infiltration and with the air preheaters (APH). This unit was placed in reserve shutdown (RSH) for economy for approximately 204 days during fiscal year 2013. It was in service the equivalent of 83 days during the fiscal year. Unit 3 was scheduled from service twice during fiscal year 2013 for a total of 76 days; the second scheduled outage was environmental. It was forced from service once for less than three days. The unit's output was limited for the equivalent of almost 19 days. When operating, Unit 3 generated an average net output of 54 MW, it had an annual capacity factor of 14%, and was in service 1,987 hours during fiscal year 2013.

In August there was a four day maintenance outage for boiler repairs. This unit began an environmental outage on October 1, 2012. The start was delayed until the completion of the Unit 6 environmental outage, which had priority. Given the low dispatch of Unit 3, plant labor issues in October and budgetary constraints, the outage schedule was extended to avoid overtime. During the outage the condenser was cleaned, condenser water gates were adjusted, seals on condenser vacuum equipment were replaced to reduce leakage, oil leaks on the BFPs were repaired, APH elements were cleaned, maintenance was performed on the forced draft (FD) and induced draft (ID) fans, damaged thermal insulation was replaced, large motors were cleaned and inspected, breakers and critical electrical equipment, including relays, were cleaned and inspected. When the unit's environmental outage was complete the unit went into RSH status in December.

Unit 3 was forced from service once by boiler tube failures. The repair of tube leaks kept the unit from available status for almost three days in February. The unit was in service with its capacity limited seven times during the fiscal year. The unit's capacity was limited three times during the fiscal year while its condenser was cleaned. The unit accrued the remaining equivalent outage days due to unresolved problems with the APHs and boiler casing air infiltration and their impact on the ID fan performance. The Authority has evaluated the cost to restore the APHs and boiler casing and concluded the expenditure would not be cost effective given the prospective limited service hours contemplated for this unit in the future,

The Authority returned Unit 3 to service on completion of its most recent major overhaul in January 2004. Since then the unit has accumulated less than 48,000 service hours towards the 60,000 hour benchmark for its next overhaul. In view of its low dispatch in the last five years, and the possible retirement or greatly reduced service hours of this unit as part of the Authority's compliance plan for MATS in the com-

ing years, the Authority has not scheduled Unit 3 for a major overhaul. The next environmental outage is scheduled for March 2014.

The following discussion applies to projects that support the entire Costa Sur Steam Plant and will be in service after the potential retirement of the two 85 MW units. The CIP includes $5.8 million for these projects in fiscal year 2014. During fiscal year 2013 work continued on the turnkey construction of a new reverse osmosis (RO) facility, including the foundation, structure and equipment, to improve the quality of make-up water supplied for demineralization. Electrical work continued on the RO facility's new power supply, which is scheduled for completion by mid-year fiscal 2014. The RO facility is scheduled to go into service in the third quarter of fiscal year 2014. Improvements to the foam fire protection system of the fuel storage tanks continued in the past year, this work had been delayed by the initial contractor's financial problems. Piping for the foam protection system to the reserve fuel tanks is scheduled to begin commissioning by mid-year fiscal 2014. The main fuel tanks dike improvements were completed at the end of fiscal year 2013; the Authority plans to complete reinstallation of the recirculation piping within six months afterwards. The reserve tank dikes are scheduled for completion in the same timeframe. Rehabilitation of the main bridge crane for Units 5 & 6 was completed in the past fiscal year.

The Authority has developed a program for compliance with the NPDES 316 (a) and 316 (b) requirements regarding its cooling water systems impact on the bay. The CIP for the three years 2014 through 2016 includes $25.0 million for these projects. The scope of work includes new floating barriers to divert fish at the intake, new higher capacity circulating water pumps and a bypass cooling water system to lower the temperature of the water returned to the bay.

CSSP Unit No. 4 (nominal 85 MW) On June 30, 2013 this unit was in an environmental outage and unavailable for service. When the unit was available for service in the past fiscal year its output was limited to 65 MW due to chronic problems of boiler casing air infiltration and with the air preheaters (APH). Since Unit 4 is a duplicate of Unit 3 it is not unusual that they have similar problems. This unit was placed in reserve shutdown (RSH) for economy for approximately 148 days during fiscal year 2013. It was in service the equivalent of 95 days during the fiscal year. Unit 4 was scheduled from service once during fiscal year 2013 for a total of 103 days. It was forced from service six times for a total of 19 days. The unit's output was limited for the equivalent of 26 days. When operating, Unit 3 generated an average net output of 47 MW, it had an annual capacity factor of 14%, and was in service 2,287 hours during fiscal year 2013.

Unit 4's environmental outage began in late March. As discussed with Unit 3, the schedule for the outage will be extended to avoid overtime and ensure maintenance personnel are made available for work at higher priority units, such as Cost Sur Unit 5 and Aguirre Unit 1. The primary scope of the outage will be the cleaning, inspections, tests, and replacements called for by the Consent Decree with the EPA. In addition, the Authority plans to replace some of the APH baskets and clean the balance of the baskets and adjust the APH seals to improve the boiler performance. Major power system equipment will be inspected, including: FD and ID fans, large pumps and motor drives, and the condenser. Relays will be tested and recalibrated as necessary. The replacement cable from the generator breaker to the normal station service transformer (NSST) will be inspected. Generator auxiliaries will be inspected, cleaned and adjusted as necessary. Components of the distributed control system and burner management system will be selectively tested and adjusted as required for reliability. Process piping leaks will be repaired. All of Unit 4's RSH hours were accumulated in the six months of October through March, when it was available but operated only during February.

The unit was forced from service for the repair of tube leaks in the boiler's economizer section twice in July for a total of six days. In February repairs of boiler tube leaks forced the unit from service twice more for a total of almost eight days. In August the unit was forced out when heavy rain lead to a detected fault in the generator's 13kV breaker; the situation was resolved in two days. In February there was a fault in the bus bars from the generator breaker to the NSST, leading to a three day outage during which insulated cable was installed to replace the bus bars. Almost all of the 26 equivalent outage days accrued during fiscal year 2013 were attributed to problems with the boiler air infiltration and APH fouling causing the ID fan to be overloaded and exceed the capacity of its motor. Less than one day of equivalent outage time was caused by condenser cleaning.

Unit 4 returned to service on completion of a major overhaul in February 2007. Since then the unit has been in service approximately 39,000 hours towards the 60,000 service hour benchmark for its next overhaul. In view of its low dispatch in the last five years,

and the possible retirement or greatly reduced service hours of this unit as part of the Authority's compliance plan for MATS in the coming years, the Authority has not scheduled Unit 4 for a major overhaul. The next environmental outage will be scheduled for 18 months after initial return to service from the current outage to comply with the requirements of the Consent Decree.

CSSP Unit No. 5 (nominal 410 MW) was offline on June 30, 2013 nearing the completion of a major overhaul. During fiscal year 2013 this unit was scheduled from service for 210 days by the Authority. A major overhaul for full gas firing accounted for almost all the outage days and two maintenance outages accounted for an additional three days; the unit was placed in RSH for two days. One forced outage accounted for less than a day on which the unit was unavailable. The unit's capacity was limited for the equivalent of two and half days during the fiscal year. Unit 5 generated an average net output of 281 MW, had an annual capacity factor of 28%, and was in service 3,641 hours during fiscal year 2013.

Unit 5 was removed from service in the first week of December to begin a major overhaul. The principal focus was to make modifications to enable the unit to operate continuously at full load with all natural gas fuel, as well as dual fuel firing of natural gas with the original design fuel of residual fuel oil; the scope was similar to that already performed on Unit 6. During the outage the scope of an environmental outage was also accomplished. The extensive scope of work performed during the major outage included repairs and modifications to the boiler, overhaul of the main turbine generator, and repairs or refurbishments to major auxiliary systems. The work on the boiler included a condition assessment to inform life extension measures for the boiler components, modifications to the convection section headers, tubing, supports and baffles to accommodate the higher furnace gas temperature associated with natural gas firing, thermocouples were installed, sections of the waterwall tubing were replaced, and refurbishing the gas recirculation fan discharge ductwork. The gas burners were cleaned and inspected. Repairs to boiler structural steel were performed. The deaerator pump was refurbished. Welds in the main steam line at the turbine regulating valves were repaired. The main turbine HP, IP and LP rotors were overhauled and the seals were replaced. The generator stator windings were rewound and new bushings installed. A Mark VI electro- hydraulic control system for the turbine was installed. The tubes in feedwater heater 3 were replaced. The turbine lube oil cooler was retubed and the lube oil system was pressure tested. The condenser was retubed, its waterboxes were blasted clean and coated, and the cathodic protection system was recalibrated. The unit is scheduled to return to service early in July, the first month of fiscal year 2014. The first of two maintenance outages was in July to repair a superheater line, it lasted 56 hours. The second scheduled outage was in November to repair a break in the reheat temperature control spray water line, it took 13 hours. In an unusual event, the unit was placed in reserve shutdown (RSH) for economy for 58 hours in July because of a transmission line constraint in the 115 kV system.

The single forced outage occurred in August as result of heavy rain causing a field ground alarm; it was resolved in 15 hours. In the past year there were four instances of limitations that totaled 62 hours; the three attributed to condenser cleaning accounted for 56 of the equivalent outage hours.

When the unit returns to service it will have completed both a major overhaul and environmental outage. The next major overhaul for this unit has not been scheduled within the next five years. The next environmental outage is scheduled to begin in December 2014.

The Authority's CIP includes $12.3 million in fiscal year 2014 for capital projects at Units 5 & 6. Since these are twin units the scopes of required work are similar and their common design promotes sharing equipment. The CIP includes funds for a replacement boiler feed pump barrel assembly, which is the pump's complete internal operational unit. The spare assembly is scheduled for delivery in fiscal year 2015 and will be compatible with the main feed pumps at Costa Sur Units 5 & 6 as well as the Aguirre Units 1 & 2. The CIP also includes funds for replacing the high pressure feedwater heaters 6 & 7 of both Units 5 & 6; they are scheduled for delivery in fiscal year 2015.

CSSP Unit No. 6 (nominal 410 MW) was in service and capable of generating at its rated capacity on June 30, 2013. In early July the unit began an environmental outage with an expanded scope to upgrade the unit for full natural gas firing. This outage lasted 85 days; subsequently there were two shorter scheduled outages totaling three and half days. It was not placed in economy shutdown in the past fiscal year. During the fiscal year 2013 Unit 6 had eight forced outages that accumulated to 18 days; the longest outage accounted for half of that total. The unit's capacity was limited for the equivalent of less than one and half days during the past fiscal year. Unit 6 generated

an average net output of 304 MW, had an annual capacity factor of 52%, and was in service 6,204 hours during fiscal year 2013.

This unit began an expanded environmental outage in the first week of July; it returned to service at the end of September. In addition to performing the mandated scope of an environmental outage, the Authority performed a wide range of maintenance and rehabilitation activities and made extensive boiler modifications to enable the unit to operate continuously at full load with all natural gas fuel, as well as dual fuel firing of natural gas with the original design fuel of residual fuel oil. The work on the boiler included a condition assessment to inform life extension measures for the boiler components, modifications to the convection section headers, tubing, supports and baffles to accommodate the higher furnace gas temperature associated with natural gas firing, thermocouples were installed, sections of the waterwall tubing were replaced, and refurbishing the gas recirculation fan discharge ductwork. The gas burners were cleaned and inspected. The reheat spray was replaced, the superheat spray control valve was refurbished, safety valves were inspected repaired and tested, air heaters were cleaned and inspected. The FD, ID, and GRF fans were inspected and maintenance performed. The GRF fan discharge duct was refurbished. Flue gas duct expansion joints were repaired. Non destructive testing (NDT) was performed on four welds at the main steam turbine control valves; the welds were last repaired in 2009. NDT was performed on a superheat line and on the deaerator. The generator, stator and hydrogen cooling systems were inspected and maintained, as was the generator's seal oil system and the excitation system. The Authority replaced the bundle in the turbine drive BFP 6-1 & 6-2 and the motor on BFP 6-2. Turbine CV 3 was repaired as was the discharge valve on BCWP 6-3. Station batteries and chargers were inspected. Electrical equipment, motors, breakers, transformers were inspected and the maintenance to ensure reliable service was performed. Routine maintenance was carried out on the air compressors and dryers. Damaged or deteriorating thermal insulation was replaced as necessary. At the conclusion of the outage in September there was a brief outage to resolve startup issues. In November a maintenance outage lasting slightly more than three days was taken to remove stop valve screens installed during the boiler overhaul.

The unit was unavailable for service for two days in October as the result of two events. The first was caused by a clogged instrument air line to the ID fans, which restricted fan control. The second was to replace the relief valve on high pressure feedwater heater 7. In February there were two successive forced outages that accounted for ten outage days. The initial event was to repair boiler tubes, which took less than a day, followed by repairs to welds in the main steam piping at the turbine control valves – these were the same welds that had passed examination during the environmental discussed above. The weld failure prompted the Authority to re-evaluate the problem and increase scheduled inspections. The same area was subsequently repaired in Unit 5 based on the latest evaluation. In March the unit was forced out for more than three days by a ground fault in the auxiliary transformer; a bushing was replaced. In May there were three forced outages, two were less than one shift, while the longest was more than a day. This outage was caused by low lube oil pressure in one of three boiler circulating water pumps, which tripped the pump. The unit's output was limited twice during the past year for an equivalent total of less than a day and half, first by the inability to fully open a turbine control valve (TCV), which was repaired during the extended outage, and secondly by broken condenser tubes causing high conductivity in the condensate.

Unit 6 returned from its most recent major overhaul in November 2009. Recognizing that the scope of the extended outage in the past fiscal year included significant portions of a major overhaul, the next overhaul will be scheduled for fiscal year 2018. Environmental outages will be performed within 18 month intervals.

Palo Seco Steam Plant

PSSP Unit No. 1 (nominal 85 MW) was in service and capable of 80 MW, on June 30, 2013. During fiscal year 2013 the unit was scheduled from service twice and was forced from service eight times. The Authority completed an environmental outage, which lasted almost 13 days, on this unit in October 2012. The scheduled maintenance outage in June also lasted 13 days. The eight forced outages kept the unit from available status for a total of almost 14 days. The unit's output was limited five times; the Authority placed the unit in reserve shutdown for economy once for a total of 13 days. The unit was in service for a total of 7,508 hours during the fiscal year; it generated an average net output of 58 MW while in service and had an annual capacity factor of 59% for fiscal year 2013.

The environmental outage was performed during the first two weeks of October. The scope included the

routine activities for an environmental outage, plus repairs to the boiler and other systems. Repairs were made to the boiler casing to reduce air infiltration. Burners were inspected, cleaned and leaks repaired. Drains valves and traps for the superheater and main steam drain valve were refurbished or replaced. The drain valve on the lower boiler drum was replaced. The soot blowers were repaired, as was a steam leak at the turbine. A leak in the normal station service transformer (NSST) was repaired. The hydrogen coolers were inspected. The condenser tubes were cleaned. An updated distributed control system (DCS) was installed to support dual fuel (oil and natural gas) firing. The scheduled maintenance outage in June to repair a leak at a generator hydrogen seal lasted almost 13 days. During April the Authority placed the unit in RSH for a total of 13 days.

In the past fiscal year the unit had the eight forced outages, however one accounted for the bulk of the 13 total forced out days. At the end of March the unit went off line to repair a failed APH main trunnion support bearing. The bearing had failed from 40 years of service. The plant fabricated two new bearings since replacement parts were not readily available and returned the unit to service in 11 days. In January acidic water from Unit 2 contaminated Unit 1 through a common condensate header. The unit was out for almost two days to restore the correct boiler water chemistry. Each of six remaining outages lasted less than five hours. In the course of the year the unit output was limited five times for an equivalent total of four days.

The last major overhaul was completed in April 2008. Based on the forecasted service hours the next major overhaul that was originally scheduled for August 2015 has been indefinitely deferred. The next environmental outage is scheduled for March 2014.

There were no capital projects budgeted specifically for Unit 1 during fiscal year 2013 and there are none budgeted for fiscal year 2014. The Authority repaired boiler casing, and seals on air heaters to reduce air in leakage and improve unit efficiency during times that the unit was in RSH for economy.

The CIP for fiscal year 2014 includes $4.4 million for the Palo Seco steam units; it is principally directed to support Units 3 & 4. In fiscal year 2012 a second distillate fuel transfer line between the Palo Seco and San Juan Steam Plants went into service. This eight inch pipe-line increased the amount of distillate fuel readily available for San Juan Units 5 & 6, thereby easing a distillate storage constraint at San Juan Station. The CIP includes funds for refurbishments to the original pipeline during fiscal years 2014 and 2015. The Authority plans to finish the foam fire protection system for the fuel storage tanks at Palo Seco during fiscal year 2014, with a total cost of $4 million. Palo Seco Units 1 and 2 entered service more than fifty years ago; the Authority has not budgeted for the conversion of these two units to gas firing.

PSSP Unit No. 2 (nominal 85 MW) was on line on June 30, 2013, however, its capacity was restricted to 55 MW because of condenser tube leaks. This unit had two brief scheduled outages for maintenance during the fiscal year. It was forced from service eight times; these outages kept the unit from available status for 24 days. This unit's capacity was limited seven times; it was placed in reserve shutdown for economy for a total of 42 days. The unit was in service for a total of 6,999 hours during the fiscal year; it generated an average net output of 55 MW while in service and had an annual capacity factor of 52% for fiscal year 2013.

The first scheduled outage in December lasted less than two days, it was to repair boiler tubes. The second maintenance outage lasted four days in February to repair a generator hydrogen seal leak. Half of the unit's RSH time of 42 was accumulated during January; the balance of the RSH hours were in October, December, and April.

Unit 2 was forced from service in July for more than four days to repair fuel oil line leak and replace piping at a feedwater valve. In August the unit was forced out for more than 12 days to repair a generator hydrogen seal leak, this was the longest single outage. In September the unit was unavailable for less than three days to replace the failed main power transformer and reserve relay. Rainwater leaking into control boxes caused two outages, once each in October and November, these lasted less a day in total. In April the unit was forced out by condenser tubes leaks for less than four days. Since the condenser tubes were lasted replaced in 2011 and the recent failures do not follow a pattern, these premature failures are disconcerting. The Authority will perform additional inspections and testing to search for the root cause of the problem. During fiscal year 2013 this unit accrued more than 15 equivalent outage days while in service with limited capacity; the most frequent cause was condenser tube leaks.

Unit 2 is scheduled for its next environmental outage in October 2013; it returned to service on completion of its most recent major overhaul in November 2007. The next major overhaul of this unit that was scheduled to begin in fiscal year 2014 has been indefinitely

deferred, based on the forecasted service hours. While the Authority will continue with routine maintenance, there are no capital projects for the unit budgeted during fiscal year 2014.

PSSP Unit No. 3 (nominal 216 MW) On June 30, 2013 this unit was out of service while performing an environmental outage that began on April 29, after a five day forced outage. During fiscal year 2013 the unit was scheduled from service seven times; once early in the fiscal year for an environmental outage, five times for maintenance and again for an environmental outage late in the year. Scheduled outages accounted for 93 days during the fiscal year. The unit was forced from service eight times; these unscheduled outages kept it from available status for a total of 47 days. Unit 3 was placed in reserve shutdown for eight days during fiscal year 2013. The unit was in service for a total of 5,215 hours during the fiscal year; it generated an average net output of 153 MW and had an annual capacity factor of 42% for fiscal year 2013.

Unit 3 began an environmental outage in early July and returned to available status 19 days later. In addition to the mandated scope of an environmental outage, routine cleaning, inspections and maintenance of auxiliary systems were performed and controls were installed for dual fuel firing, that is fuel oil and natural gas. Four days after returning to service there was a maintenance outage of less than one day duration to repair a pipe leak in the superheat spray system. A two day maintenance outage in August was taken to rebalance the LP turbine. During another two day outage in September boiler leaks were repaired and the APH cleaned. The second environmental outage began at the end of April following a forced outage that was initiated by broken refractory clogging the air preheater baskets and then subsequently when the LP turbine encountered high vibration during restart. Six of the eight days in RSH were accumulated in January.

Two of the eight forced outages were one shift in duration, the other six ranged from one to 18 days in length. In October the unit was forced from service for 18 days to replace LP turbine bearing 1, following over temperature and vibration. In November the boiler water pH became too acidic leading to a one outage to remedy. In December there two outages to repair boiler tube leaks, these lasted a total of ten days. Repairs to the furnace waterwall and boiler tubes forced a two day outage in January. In February there was a fire caused by a ruptured flexible fuel hose in one burner corner; repairs to this forced outage took 13 days. In April failed duct refractory fell onto the unit's APH. The clogged baskets restricted air flow and the unit taken out of service for cleaning. During restart after the outage the LP turbine exhibited high vibration. Based on the severity of the vibration the unit was scheduled to begin its environmental outage early. Examination of the LP turbine revealed stage L-1 blade movement and collateral damage; bearing 3 was also in poor condition. During the outage NDT was performed on the main steam piping to confirm its condition was satisfactory, although its design is the same as that on Unit 4 which had cracks. During the past fiscal year the unit operated with some limitations principally due to cooling issues with the circulating water system, these totaled five equivalent outage days.

The schedule for the next environmental outage for Unit 3 will be established after the unit returns to service from the repairs of its LP turbine. The unit returned to service following completion of its most recent major overhaul in November 2009. Its next major overhaul is included in the projected CIP for fiscal years 2016 and 2017 when it will be coordinated with the modifications to make this unit capable of firing gas. The CIP for fiscal year 2014 includes funds for repairs to the LP turbine and rehabilitation of the boiler. The scope of the boiler work includes replacing boiler corners and superheat header 5, repair of superheater header 6, and replacing air preheater baskets and seals.

PSSP Unit No. 4 (nominal 216 MW) was in service, capable of full output on June 30, 2013. This unit was scheduled from service for a total of 49 days during fiscal year 2013 for three maintenance outages and an environmental outage. It spent one day in reserve shutdown for economy. In the past fiscal year the unit accumulated six forced outage days from ten incidents, of which four lasted one day each. The unit's output was limited four times, with the total equivalent outages of ten days. The unit was in service for a total of 7,421 hours during the fiscal year; it generated an average net output of 144 MW and had an annual capacity factor of 57% for fiscal year 2013.

The unit was scheduled from service for three and one half days in August to clean the APH baskets; the deteriorating baskets had become a chronic problem that limited the unit's capability. In November the unit began a 33 day environmental outage. In addition to the required maintenance, cleaning, inspections and tests, the Authority installed an upgrade to the distributed control system (DCS) for dual fuel firing, that is natural gas in addition to fuel oil. During the outage the APH baskets and seals were replaced;

the normal station service transformer (NSST) was replaced with one of more capacity. Refurbishing the two air preheaters increased the boiler's performance and the unit's capacity. There was a one day maintenance outage in March to replace the seat of a boiler safety valve. In April the unit was out for ten days to repair the main steam piping at the stop valve and perform NDT on the opposite line; Unit 3's similar piping was also examined. This unit was placed in RSH for one day in December.

Unit 4 was forced from service ten times for a total of six days. There were four one-day forced outages, the balance of unscheduled outages were random and brief. In November the unit was forced from service for a day because of low pH in the boiler water, which resulted from a failed pH meter. The unit was forced out for one day in December to repair boiler tube leaks and another day to repair an internal fault in the motor control center feeding the boiler feed pump. A contractor punctured a buried cooling water line in May while extending the fire protection foam piping to a fuel oil tank; the unit was out for one day. The unit remained in service with limited capacity for a total of ten equivalent outage days principally due to fouled APH baskets prior to their replacement.

The next environmental outage is scheduled for April 2014. The unit returned to service following completion of its most recent major overhaul in July 2009. Its next major overhaul is included in the projected CIP for fiscal years 2016 and 2017 when it will be coordinated with the modifications to make this unit capable of firing gas. The CIP for fiscal year 2014 includes funds for a training simulator of the plant, including the high voltage gas insulated switchgear interface, and rehabilitation of the boiler, during which it will receive new boiler corners, burners, valves, and a new burner management system. The CIP includes funds for the rehabilitation of the turbine generator as part of the next major overhaul.

San Juan Steam Plant

Units 1, 2, 3, & 4 have been retired from service for more than three decades. Units 5 & 6 are discussed under the *Combined Cycle Plant* section.

SJSP Unit 7 (nominal 100 MW) was not in service on June 30, 2013; it was out for repairs to the circulating water traveling screens. During fiscal year 2013 scheduled outages kept Unit 7 from service for 100 days. The longest outage was an environmental and there were six maintenance outages. Unit 7 was placed in reserve shutdown for economy for nine hours during the past fiscal year. There were four forced outages that kept the unit from service for 30 hours in total. The unit's operating limitations were three equivalent outage hours in the past year. During the 6,326 hours that Unit 7 was in service it generated an average net output of 74 MW and had an annual capacity factor of 54%.

The environmental outage for Unit 7 began late in February. In addition to all the required inspections, cleanings and tests required for compliance with the Consent Decree, the scope of work included maintenance on turbine control valves, cleaning the boiler feed pump motors, repairing boiler tubes, assessment of the boiler's condition, and beginning the installation of new control wiring from the electrical room to the control room for regulation of the unit output, to replace old and damaged wiring. The scope of work was expanded to include removal of known asbestos insulation where the metal jacketing was deteriorating and beginning to expose the asbestos insulation. All the insulation containing asbestos was abated from the low pressure feedwater heaters and piping. The unit was out of service for 82 days for this extended outage. Previously, in August the unit was scheduled out for a four day maintenance outage to repair turbine control valves and clean the coolers for the turbine's main oil tank. There were two maintenance outages in September for less than two days in total to repair leaks in the fuel oil heaters and clean the condensate filters. There was a three and a half day scheduled outage in January to repair leaks in the auxiliary steam piping. There as a brief maintenance outage in mid-June to replace deteriorated wiring at the main turbine control valve. Late in June the unit began a maintenance outage to repair circulating water traveling screens; the work extended into early July.

During the past year the unit was forced from service four times for a total of 30 hours, of which one outage accounted for 20 hours. In November the unit was forced out for almost a day to replace a failed turbine lube oil pump motor. Two other forced outages were to replace a burner control system solenoid and a failed motor control relay for a boiler feed pump. The last forced outage was in February to repair leaking boiler tubes; after an hour this outage transitioned to the scheduled environmental outage.

Since all the steam plant units at San Juan have experienced an increase in trips associated with various control system's reliability, the Authority has increased its focus on improvements to control system maintenance activities, including replacing old cables, and operator training.

Unit 7's next scheduled outage will be an environmental outage in May 2014. It is scheduled for an overhaul late in fiscal year 2015. During the overhaul the turbine, generator and boiler will be refurbished to the extent consistent with the unit's forecasted low utilization for compliance with the air regulations that will be in effect after that. The unit is not scheduled for conversion to gas firing. This unit's last overhaul was completed in fiscal year 2008.

The station's capital projects in the CIP for the four steam units for fiscal year 2014 total $4.7 million. The funds are directed to improvements in the plant circulating water traveling screens, cathodic protection of the condensers, revisions to discharge water streams for compliance with the NPDES criteria. In addition the Authority will continue its program of rehabilitation of the plant fuel storage tanks.

SJSP Unit 8 (nominal 100 MW) was online, capable of full output on June 30, 2013. This unit was scheduled from service four times for maintenance during fiscal year 2013 for a total of 33 days. Unit 8 was placed in reserve shutdown for economy for four and one half days during the past fiscal year. The unit was forced from service sixteen times, accruing a total of less than nine forced outage days during the fiscal year. During the 7,644 hours that Unit 8 was in service it generated an average net output of 72 MW and had an annual capacity factor of 63%.

The unit's first maintenance outage was in September to clean the condenser waterboxes and tubes; it returned to service after three days. In November there was a 12 day maintenance outage to repair tubes in feedwater heater 6 and clean the oil side of the turbine lube oil cooler. In December the unit was scheduled out for five days to replace the bonnet gasket in the main stop valve and to plug tubes in feedwater heaters 2 and 3. There was a 14 day outage beginning in late May to repair tubes in feedwater heater 5 and inspect the generator hydrogen cooling system for leaks at the bearing and coolers. This unit was placed in reserve shutdown for economy for four days in November.

Three of the forced outages for boiler waterwall repairs in Unit 8 during the past year accounted for 65% of the total hours lost to forced outages; only one more forced outage lasted a day. Some of the dozen remaining outages were caused by problems with aging control elements (such as switches, sensors and relays) and control wiring, consequently the Authority has increased inspections and replacement of suspect components in the plant's controls. As with Unit 7, the Authority has begun replacing old control wiring with new control wiring in Unit 8 from the electrical room to the control room for regulation of the unit output. Except for those discussed below, forced outages were brief and the unit usually returned to service following completion of corrective action within one shift. In July, October and December the unit was out of service for a total of almost six days to repair boiler waterwall tube leaks. Unit 8 was forced from service in April for the repair of a circulating water pump coupling, the repair was completed and the unit was placed in service in one day. This unit had no equivalent outage days in the past fiscal year.

Unit 8's next scheduled outage will be an environmental outage in August 2013. It returned to service on completion of its most recent major overhaul in November 2010. It is scheduled for a major overhaul early in fiscal year 2017. During the overhaul the turbine, generator and boiler will be refurbished to the extent consistent with the unit's forecasted low utilization for compliance with the air regulations that will be in effect after that. The unit is not scheduled for conversion to gas firing.

SJSP Unit No. 9 (nominal 100 MW) was online, capable of full output on June 30, 2013. Unit 9 began service during the past fiscal year in August; service was delayed for installation of the refurbished LP turbine. The unit was scheduled from service seven times for maintenance during fiscal year 2013 for a total of 33 days. Unit 9 was placed in reserve shutdown for economy for 14 days during the past fiscal year. The unit was forced from service nine times, accruing a total of 38 forced outage days during the fiscal year, including the LP turbine outage that began the year. During the 6,720 hours that Unit 9 was in service it generated an average net output of 72 MW and had an annual capacity factor of 55%.

The first two scheduled maintenance outages were in August to support testing and make adjustments following startup after the LP turbine was restored; these lasted eight days in total. Transport time and refurbishment of the LP turbine in a mainland shop had taken effectively all of fiscal year 2012, consequently the unit did not begin recovery startup until the first of August. In October the unit was scheduled out for less than a day to repair leaks at various vents and drains. There was a ten day maintenance outage in December to repair boiler waterwall tube leaks. In March the unit was scheduled out for 12 days to change a recirculation valve for one of the boiler feedwater pumps and to correct a hydrogen leak at the generator bearing 5. During a brief maintenance out-

age in April a leak in the main steam stop valve seat drain was repaired. In May the unit was scheduled out for less than two days to repair tube failures in the primary superheater. The unit was placed in reserve shutdown for economy for 14 days in March and April.

The longest forced outage was the continuation of the forced outage caused by the LP turbine blade failure at the beginning of fiscal year 2012. This outage accounted for 32 of the 38 days the unit was forced out during fiscal year 2013. In August the unit was forced out of service for two days to repair boiler waterwall tubes. There was a two day outage in May to repair tubes in the boiler reheat section. The other forced outages were brief, with four related to various control system problems and one operator error. The unit's only equivalent outage hours were five in February.

The unit is scheduled for an environmental outage in November 2013. It is scheduled for conversion to gas firing in fiscal year 2017, in conjunction with modified scope of a major maintenance. The unit's last major maintenance was completed in August 2012.

SJSP Unit No. 10 (nominal 100 MW) was unavailable for service after being forced from service to repair a failed air preheater trunnion thrust bearing late in June 2013. Repairs are scheduled for completion in the first ten days of fiscal year 2014. This unit was scheduled from service three times for maintenance and once for an environmental outage; in total these outages kept it from service for 48 days. The unit was placed in reserve shutdown for economy for one day. It was forced from service 13 times; as a result of these outages the unit accrued 16 outage days. The unit accrued one equivalent outage day while unable to generate at its nominal capacity. During the past fiscal year Unit 10 was in service 7,198 hours, it generated an average net output of 72 MW and had an annual capacity factor of 58%.

In July the unit was scheduled for a maintenance outage to repair the thrust collar on the air preheater (APH) 10-1 trunnion bearing. During the nine and a half day outage the plant fabricated and installed replacement parts; the unit then returned to service. A 29 day environmental outage began during the first week of September, ending in October. In addition to all the required inspections, cleanings and tests required for compliance with the Consent Decree, the scope of work included the transition to an upgraded distributed control system and beginning improvements to control wiring from the electrical room to the control room for regulation of the unit output, to replace old and damaged wiring, and removing abandoned control wiring from cable trays. During this outage the repair fabrications for the trunnion bearing in APH 10-1 were inspected by NDT and found satisfactory. Two weeks after returning from the environmental outage the unit was scheduled for a maintenance outage of less than three days to repair tube leaks in feedwater heater 5. In January the unit was scheduled out of service for seven days to repair multiple leaks in the extraction steam piping and to repair leaks in the atomizing steam at the burners. The unit was placed in reserve shutdown for economy twice for a total of one day.

The longest forced outage for this unit occurred in January when high condensate conductivity forced the unit from service. Leaking condenser tubes were plugged; the unit returned to service eight days after being removed from service. A variety of control system problems accounted for five days of the remaining forced outages, many of which were brief. In October the unit tripped three times due to instability in the boiler water level control, the third trip was initiated by electric system transients; these outages resulted in two days out of service. The boiler water level controls were adjusted. In November the unit was tripped once by a false signal of loss of fuel and then by control problem resulting in high main steam temperature. In March the unit was tripped by a fault in the generator lockout caused by a defective cable that was replaced. This unit tripped twice in May. The first was caused by an electric system rapid load change while the unit was operating in regulation, resulting in a trip from low boiler water level; the boiler water level controls were retuned. The second outage in May was caused by operator error inadvertently energizing a generator protective relay. The last forced outage of the past fiscal year was to repair the trunnion bearing on APH 10-1 at the end of June. The fabricated repair parts installed a year earlier did not survive the duty. New replacement bearing components were being installed at the end of the fiscal year.

Unit 10 is scheduled to begin an environmental outage in November 2013. The unit returned from a major overhaul in August 2009 and is scheduled for a major overhaul in fiscal year 2016, when the scope of the work will include gas conversion.

Combined-Cycle Plant

Total Generating Capacity 1,032 MW

The combined-cycle units located within the Aguirre generating complex contain 592 MW and the San Juan Units 5 & 6 located within the San Juan Steam Plant add 440 MW of dependable combined cycle

capacity to the System. The status of these combined cycle units is discussed below.

Aguirre Combined-Cycle Plant

This combined-cycle plant is comprised of two duplicate units, both rated at 296 MW. Each unit consists of four combustion-turbines (CTs), each rated at 50 MW, with individual heat recovery steam generators (HRSGs), i.e. boilers, powering a single 96 MW steam turbine-generator (ST). This configuration yields a unit capacity of 296 MW and a total plant capacity of 592 MW. These units are primarily used for cycling duty. During fiscal year 2013 the Aguirre Combined Cycle plant recorded a net capacity factor of 6% while generating 1.5% of the total System's net generation. The station's net generation for fiscal year 2013 was approximately 20% less than the previous fiscal year. At the end of fiscal year 2013 the steam turbine for Unit 1 was unavailable, the steam turbine-generator in Unit 2 was available with significant limitation and all of the eight CTs were available for service.

In the following discussion the CTs and steam turbine-generators at this plant are identified by unit and number and with respect to CTs by order within the unit, i.e. the second CT in Unit No. 1 is numbered CT 1-2 and the steam turbine-generator in Unit 2 is identified as ST-2.

When the four CTs of a unit are in combined service the associated steam turbine-generator is rated as having a design capacity of 96 MW. Compromised steam production caused by exhaust duct seal leakage and poor steam condenser performance have combined to impose long term limitations on the capacity of the steam turbine-generators in both units, however. In fiscal year 2004 the Authority began a program to replace the poorly sealing diverters upstream of each HRSG. The diverters were leaking hot combustion turbine exhaust gases to atmosphere before the hot gases passed through the HRSG. The loss of hot gas reduced the amount of steam generated in each HRSG to below the quantity required for its associated steam turbine to generate at design conditions. The last of the eight new design diverters was installed in fiscal year 2012. Since the seals on several of the replacement diverters have been in service for eight or nine years they are now in need of replacement. Consequently, the Authority has begun a second round of replacing the diverter seals.

In addition to the losses attributed to poorly sealing diverters, the two steam turbine- generators are also limited by inefficient condensing operations. The high temperature of the cooling water in the closed loop cooling system is a major factor limiting the efficiency of the condensers. Periodic cleanings and removal of scale deposits from the condenser tubes have improved condenser vacuum and each unit's heat rate. The Authority plans to refurbish the cooling towers and replace old vacuum pumps during scheduled overhauls.

Recognizing the age of the original combustion turbines' technology, the Authority has completed an upgrade of the combustion system on all eight of the station's CTs. The upgrade brings the CTs to a modified Frame 7EA design, which gives the CT the capability of operating at a higher combustion temperature, thereby improving its efficiency. Additionally the fired hours between combustion inspections, formerly every 4,000 equivalent fired hours (EFH), is increased to every 5,300 EFH. This increase in EFH has increased the interval between combustion inspections by six or more months. The replacement of the air inlet filter houses and filter media was performed concurrent with the CT's upgrade. An upgrade of the distributed control system (DCS) has been completed in both units. Following the decision in 2009 to suspend the construction of a pipeline that would have brought natural gas to these CTs the Authority blinded off the eight modules that gave the station dual fuel firing capability, put the nozzles in protected storage, and installed climate control air conditioners in each of the modules. The dual fuel modules have not been commissioned. During the past year the OEM began an evaluation of the turbines for conversion to dry low NOx combustors firing natural gas. This technology would increase the potential operating hours on natural gas by reducing its emissions. The combined cycle plant will utilize a portion of the natural gas slated for delivery to the Aguirre plant.

The Authority's CIP for fiscal year 2014 includes funds for completion of the overhaul of the steam turbine for Unit 1, rehabilitation of the cooling towers and scheduled inspections the combustion turbines CT 2-1 and CT 2-3. The budget for these projects in fiscal year 2014 is $7 million.

ACCP Unit No. 1 was available for service and capable of generating 200 MW on June 30, 2013. The four CTs that comprise this unit were available for service at their rated capacity of 50 MW. The steam turbine-generator was out of service for the overhaul described below.

CT 1-1 was available for service 8,718 hours during fiscal year 2013 and was in service 471 hours. This CT had two brief maintenance outages and four

forced outages in the past year. None of the outages lasted more than ten hours and none of the causes were repeated. The maintenance outage in February lasted eight hours to reconnect the auxiliary transformer to CT 1-2. In March there was a seven hour maintenance outage to replace a breaker at the station transformer. Both of these maintenance outages effected all four CTs in Unit 1, except for CT 1-3 which was already out of service in March for generator rotor repairs. One forced outage of nine hours for CT 1-1 was caused by a false high temperature signal from the main power transformer which tripped all four CTs in Unit 1 in August.

CT 1-2 was available for service 8,716 hours during fiscal year 2013 and was in service 608 hours. In addition to the two common maintenance outages and one common forced outage, this CT had three forced outages. Two forced outages were initiated by high pressure alarm in the exhaust duct, these lasted four hours in total. In February the repair of the combustion turbine cooling fan forced the unit out for 17 hours.

CT 1-3 was available for service 5,625 hours during fiscal year 2013 and was in service 601 hours. In addition to the common February maintenance outage and the one common forced outage, this CT had another scheduled maintenance outage and six forced outages, one of which extended into a maintenance outage. In October CT 1-3 and CT 1-4 were scheduled out of service for five hours to repair an oil leak in their shared main power transformer. Three of the forced outages totaled seven hours. Repair of a fuel pressure instrument line forced the unit out for 17 hours in October. In December the unit was forced out for 15 hours to repair a leak in the instrument tubing at the high pressure fuel filter. In February the unit was forced out with a failed restart; the generator rotor required rewinding. In March the outage was classified as a maintenance outage. The repaired rotor returned to the plant and was installed before the end of June.

CT 1-4 was available for service 8,717 hours during fiscal year 2013 and was in service 794 hours. This CT had three common scheduled outages as discussed above for CT 1-3. The CT also shared one forced outage with the others in Unit 1. In addition CT 1-4 had one forced outage in June lasting 19 hours caused by mis-operation of the generator breaker. In the past fiscal year the hours of operation for CT 1-4 were second only to CT 2-1.

ST-1 was available for service 5,703 hours in the past fiscal year and was in service 701 hours. During fiscal year 2013 the steam turbine had three scheduled outages and five forced outages. Four of the forced outages accumulated 20 hours and all were less than ten hours in duration. A forced outage in January lasted 13 hours to correct faulty condenser hotwell level control. The first scheduled outage lasted 33 hours in October to repair an oil leak in the unit's main power transformer and repair a breaker. In February the steam turbine was scheduled out with the Unit 1 CTs for eight hours to reconnect the auxiliary transformer. Later in February the steam turbine was scheduled out of service to repair hydrogen leaks at the generator bushings. In April ST-1 began a scheduled major inspection. The previous major inspection was completed in 2000. The planned work is scheduled to be completed in the first quarter of the fiscal year 2014.

During the turbine outage the Authority plans to address maintenance activities, including structural repairs to the cooling tower and installing new cooling tower fill. The condenser vacuum pumps will be refurbished, the condenser will be mechanically and chemically cleaned, the condenser expansion joints will be replaced and the condenser waterboxes will be repaired. The boiler feed pump will be requalified and the circulating water pump impellers will be trimmed to prevent overloading its motor. The 48" and 60" diameter cooling piping from the cooling tower will be inspected. The major inspection of the steam turbine will include rewedging the generator stator, rewinding the generator rotor, and replacing the LP first stage buckets. Electrical inspections of bushings, auxiliary components, and transformers are scheduled.

ACCP Unit No. 2 was available for service and capable of generating 265 MW on June 30, 2013. The unit's four CTs were available for service, each was capable of generating 50 MW; ST-2, the steam turbine-generator was available but limited to 65 MW due to condenser performance issues.

CT 2-1 was available for service 8,584 hours during fiscal year 2013 and was in service 1,109 hours. During the past fiscal year this CT was scheduled out of service four times and forced out once. The one forced outage lasted two hours to replace a defective control card. In November the CT was scheduled out of service 55 hours to repair a faulty flame scanner. The following month the CT was out for 100 hours for scheduled maintenance on the main power transformer. In January the CT was out seven hours while its auxiliary transformer was reconnected. A corroded section of fuel piping was replaced in February during a six hour outage.

This CT is scheduled for an inspection during fiscal year 2014. CT 2-1 had the best net heat rate of all the CTs and its service hours were more than any other CT.

CT 2-2 was available for service 8,193 hours during fiscal year 2013 and was in service 689 hours. During the past fiscal year this CT was scheduled out of service three times; it was forced out twice. During December the CT had a scheduled combustion inspection. The air intake ducts were replaced, as were the radiators and fuel oil recirculation line. The lube oil tank was cleaned. While the CT was out of service, scheduled maintenance on the main power transformer was performed. In January the CT was out seven hours, along with CT 2-1, while its auxiliary transformer was reconnected. In June the CT was out of service to allow replacement of the expansion joint at the HRSG diverter. In September this CT was forced out for six hours to replace a defective relay control card. In December it was forced out of service for 106 hours to correct problems caused by low level in the lubricating oil system.

CT 2-3 was available for service 8,709 hours during fiscal year 2013 and was in service 632 hours. During the past fiscal year this CT was scheduled out of service two times; it was forced out three times. The two scheduled outages accrued 11 hours out of service; one outage was to replace a cable from the NSST and the other was to replace a radiator. A forced outage in September lasted six hours to replace a defective relay control card. Two events, in October and December, added two hours more of forced outage time for the balance of the fiscal year. During fiscal year 2014 this CT is scheduled for a major inspection during which its compressor section will be replaced with the spare compressor section. The compressor from CT 2-3 will be sent for refurbishment; it will be stored as a spare following its return.

CT 2-4 was available for service 7,998 hours during fiscal year 2013 and was in service 522 hours. During the past fiscal year this CT was scheduled out of service three times; it was forced out twice. In October the CT was scheduled out for seven hours to replace a cable from the NSST, concurrent with CT 2-3. In February the CT had a combustion inspection. Based on prior inspections by a technical advisor, bearing 2 was replaced. This outage lasted 517 hours and the CT returned to available status. In March the CT was inspected to verify alignment of the mechanical accessories, this outage lasted eight hours.

ST-2 was available for service 7,837 hours in the past fiscal year and was in service 1,062 hours. During fiscal year 2013 the steam turbine had four scheduled outages and ten forced outages. Two of the scheduled outages and one forced outage were to repair circulating water system piping. In August the steam turbine was unavailable for 60 hours to repair corrosion / erosion in the 60" diameter circulating water line at the pump discharge. The turbine was forced out of service for 67 hours in September to repair a break in the circulating water piping manhole at the condenser. Scheduled repairs in October to the buried circulating water piping and manhole required an additional 740 hours. Two brief scheduled outages in March accrued ten hours in total. In September the steam turbine was forced out twice more, the first lasted six hours to repair a protective relay for the main power transformer; the second was caused by the turbine control valve failing to operate over its full range, this was repaired in 18 hours. The remaining seven forced outages were brief and accumulated 20 hours in total.

San Juan Combined Cycle

Units 1, 2, 3, & 4 have been retired from service for more than three decades. Units 7, 8, 9 & 10 are discussed in the *Steam-Electric Production Plant* section.

SJ Unit 5 (Dependable Capacity of 220 MW) is a combined cycle unit comprised of CT 5, a combustion turbine with a capacity of 160 MW and ST 5, a steam turbine with a capacity of 60 MW. The unit began commercial operation in October 2008. During fiscal year 2013 Unit 5's combustion turbine was available for service 6,909 hours and in service 4,394 hours, which was a decline of one-third in the service hours from the previous year. When in service the combustion turbine's average net generation was 114 MW. In fiscal year 2013 the unit's steam turbine was in service 4,250 hours of the 8,438 hours that it was available for service; it generated an average of 40 MW. For fiscal year 2013 Unit 5 generated 3.2% of the total System power and achieved a net capacity factor of 35%.

The Authority has a long term multi-year service agreement with the combustion turbine vendor to provide technical advice and to perform inspections of the combustion turbine generators and the steam turbine generators that comprise San Juan Units 5 & 6. The Authority is responsible for the inspection and maintenance of auxiliary equipment in these units. A discussion of the frequency of the contracted inspections and their scope is found in the *Maintenance* section above.

SJ CT 5 was available for service and capable of generating 160 MW on June 30, 2013. During fiscal year 2013 this CT was scheduled from service eight times; these outages kept it from service for a total of 64

days. It was forced from service eight times and accrued a total of 14 forced outage days as a result. CT 5 was in service approximately 183 days and was in reserve shutdown 105 days.

This combustion turbine had six scheduled outages between July and October, prior to its scheduled Modified Combustion Inspection at 32,000 ESH. The CT was scheduled out of service twice in July and August for a total of two days to do weld repairs on the generator hydrogen piping. An equal amount of time was spent in August and September during two outages to replace the turbine inlet pre-filters. In September the CT was scheduled out twice for a total of less than a day while the ST 5 circulating water filters at the condenser were cleaned. The Authority replaced the inlet air filters in a two day scheduled outage in June. The operating life of the inlet filters and pre-filters has improved since completion of construction of the GIS structure, its associated improvements and paving the areas that are adjacent to Units 5 & 6 combustion turbines. The scheduled inspection took the combustion turbine out of service from October to mid-December. The scope of the Modified Combustion Inspection includes replacement of fuel nozzles, combustor baskets, transition pieces, turbine blades in rows 1, 2, 3, and 4, and turbine vane and ring segments in rows 1 and 2. Inspections of the inlet, compressor, turbine, and exhaust sections of the combustion turbine were also performed. The return to service was delayed by observed high vibration and rebalancing the power turbine.

The longest forced outage for CT 5 was caused by repairs of a steam control valve dump at the condenser of Unit 5's steam turbine. This forced CT 5 from service for a total of almost six days in the beginning of July. A leak in the circulating water piping sprayed sea water on the condensate pump motor causing the pump and the steam turbine to trip; this outage lasted nine hours. Additional repairs to the circulating water piping in March forced a steam turbine outage lasting less than three days. Temporary repairs were completed and the CT returned to available status; permanent repairs have been added to the plant's CIP. During three forced outages in May the CT accrued more than four days out of service as the result of incorrect set points or logic in the DCS; these stemmed from migration of old files into the updated DCS. These values were checked and corrected. The two other events that forced CT 5 from available status were each resolved in one shift or less and their causes were unrelated.

The Authority has scheduled CT 5 to come out of service in January 2014 for a Combustion Inspection. During this work the generator will be rewedged and upgrades to the HRSG will be incorporated. The CIP includes funds for purchasing the parts to modify both of the combustion turbines for dual fuel capability, firing natural gas or distillate. The conversion work is scheduled for fiscal year 2017.

SJ ST 5 was capable of generating 60 MW on June 30, 2013. During fiscal year 2013 it was in service 177 of the 352 days that it was available for service. In the past fiscal year this steam turbine was scheduled for maintenance four times during which it accrued four days out of service. Seven unscheduled service interruptions forced ST 5 to be unavailable for service for a total of ten days in the past fiscal year. The Authority placed the steam turbine in reserve shutdown for economy for 175 days during the fiscal year.

This steam turbine was scheduled out of service on two successive days in September to clean circulating water filters at the condenser; the operation took one day in total. In March the turbine was scheduled out for 6 hours to replace its hydraulic control system oil filters. The last scheduled outage was in June while CT 5 air filters were replaced, which lasted two days.

The longest forced outage was to repair a steam control valve dump at the condenser of Unit 5's steam turbine. This forced ST 5 and CT 5 from service for a total of almost six days in the beginning of July. Repairs to the circulating water piping in March forced a steam outage lasting less than three days. Temporary repairs were completed and the ST returned to available status; permanent repairs have been added to the plant's CIP. The three forced outages in May for CT 5 described above had similar consequences on ST 5, which accrued 15 hours unavailable from these incidents.

SJ Unit 6 (Dependable Capacity of 220 MW) is functionally a duplicate of the combined cycle Unit 5, with CT 6 being a 160 MW combustion turbine and ST 6 being a 60 MW steam turbine, ST 6. This unit also began commercial operation in 2008. On June 30, 2013 both the combustion turbine and steam turbine in Unit 6 were available. During fiscal year 2013 the unit's combustion turbine was available for service 8,741 hours and was in service 3,071 hours; while operating it generated a net average of 127 MW. In the past fiscal year the steam turbine was available for service 4,414 hours and was in service 2,183 hours; while operating it generated a net average of 42 MW. For fiscal year 2013 Unit 6 generated 2.3% of the System power and achieved a net capacity factor of 25%.

SJ CT 6 was available for service and capable of generating 160 MW on June 30, 2013. During fiscal year 2013 this CT was not scheduled from service; it was forced from service six times and accrued a total of 18 forced outage hours as a result. CT 6 was in service approximately 128 days and was in reserve shutdown 236 days.

For CT 6 the average duration of each forced outage was three hours; the causes were not repetitive and their occurrences were infrequent. In chronological order, the outages were caused by a failure in the 480 volt auxiliary electrical system, weld repairs to a fuel line, repair of the master trip relay associated with new control system components, CT exhaust gas path condition trip, incorrect operation of a 115 kV breaker and failure of the air conditioning units for the generator exciter room.

The Authority has scheduled CT 6 to come out of service in August 2013 for a Combustion Inspection. During the outage the turbine will be inspected to identify the cause of high vibration in bearing #2. The CIP includes funds for purchasing the parts to modify both of the combustion turbines for dual fuel capability, firing natural gas or distillate. The conversion work is scheduled for fiscal year 2017.

SJ ST 6 was capable of generating 60 MW on June 30, 2013. During fiscal year 2013 it was in service 91 of the 184 days that it was available for service. This steam turbine began the past fiscal year out of service while waiting for the return and installation of the repaired generator rotor. This repair work plus a second repair cycle for the rotor put the steam turbine into outages totaling 180 days in fiscal year 2013. Four short unscheduled service interruptions forced ST 5 from service for less than a day in total. The Authority placed the steam turbine in reserve shutdown for economy for 93 days during the fiscal year.

The failure of CT 6's generator late in fiscal year 2011 had caused the Authority to put ST 6 in reserve shutdown for economy. In fiscal year 2012 it was accruing days in reserve shutdown for economy when Unit 5's steam turbine generator rotor failed. To return Unit 5's steam turbine to available status, the Authority installed the Unit 6 generator rotor into ST 5's generator. This switch enabled Unit 5 to return to combined cycle service in the second quarter of fiscal year 2012. The generator rotor from ST 5 was sent to a mainland facility to be refurbished. It was returned to Puerto Rico for installation in ST 6 in August; the steam turbine was ready for service in September. After less than 100 hours in operation the rotor failed again. In October the OEM removed the rotor and sent it for repairs. The repaired rotor returned to the island in December and the steam turbine was available for service in January. In each of the next four months there was a single forced outage; these accrued 19 forced outage hours in total. Two of the outages were triggered by trips in the combustion turbine.

During the scheduled outage of CT 6 in August the generator will be cleaned and inspected. The Authority plans on performing full maintenance and potential upgrades to ST 6 while CT 6 is in its next major inspection. During fiscal year 2014 the Authority has scheduled performance tests to identify potential improvements in the steam turbine.

Combustion-Turbine Power

Total Generating Capacity 846 MW

Cambalache Combustion-Turbine Power Blocks

These units were designed to provide rapid response spinning reserve, to ensure System stability in the event of the unanticipated loss of a large generating unit and thereby improve the reliability of service to the Authority's clients. The three combustion turbines at Cambalache comprise a plant rated at 247.5 MW. Prior to the return of the four Palo Seco units and the addition of new combined cycle capacity at San Juan in 2009, the Authority had dispatched at least one unit daily at partial load. During the past four years, however, the Cambalache units have been dispatched sparingly and were not in daily service. The low level of dispatch has been driven by the high cost of Cambalache's distillate fuel and lower System demand. Unit 1 was unavailable for service for all of fiscal year 2013, consequently the station had an availability factor of 63%, however, the two operable units averaged 95% availability. The two operable units produced approximately 0.3% of the total System's generation in the past fiscal year.

Despite their high availability Units 2 and 3 each operated less than 500 hours during the past fiscal year. Given the low dispatch rate, it was typical that a unit could return from an outage or inspection and be available, but not be promptly placed in service. To ensure their reliability the Authority rolls each unit twice weekly. The plant's air permit allows 780 unit starts per year, the equivalent of five starts per unit per week; the number of starts in the past fiscal year did not approach the allowable number of starts.

The Camabalache units are located near Arecibo on the island's north coast, approximately 40 miles west of the San Juan metropolitan area. As discussed in the *Capacity and Energy Resource Planning* section, by

the end of fiscal year 2012 the Authority had elected to pursue alternative off-shore natural gas supply arrangements and stop work on the Via Verde Project which would have routed a gas pipeline close to the Cambalache plant. With no firm plans for the supply of natural gas in the vicinity of the plant, the Authority deferred work to convert the Cambalache units to dual fuel firing, with the addition of natural gas. While the Authority has awarded a contract to the original turbine manufacturer for the conversions of the three combustion turbines and the components for the conversion are in storage at the station, the vendor has not been released to install the equipment; this work is no longer included in the CIP. The scope of the fuel conversion is well defined and each unit would be unavailable for approximately 30 days for the conversion. Before starting these conversions the Authority will need a revised Prevention of Significant Deterioration (PSD) Air Permit. Since it can be prepared relatively quickly, the Authority did not submit the PSD application to the EPA during fiscal year 2013.

Although the Cambalache combustion turbines operate in an open cycle, each machine exhausts to a heat recovery steam generator that provides steam for NOx control and power augmentation. The steam generators are referred to as a once-through steam generator (OTSG) and were specifically designed to withstand dry operation, i.e. the hot exhaust gases can pass through the steam generator while it is empty and producing no steam. The steam from the OTSGs is made from demineralized water produced on site in a water treatment facility common to all three units. Raw water is drawn from local wells and stored on site in a 1.25 million gallon tank; half of that capacity is reserved for fire fighting. The water treatment facility includes storage of 2.4 million gallons of demineralized water. During startup and fast load ramping, demineralized water is injected into the combustion turbines to compensate for insufficient steam.

Combustion turbine technology has continued to advance since the development of the turbines installed in Cambalache and the original equipment manufacturer (OEM) has offered improvements that could increase the power of each machine by approximately 16 MW. The Authority decided to defer this capital commitment indefinitely, however the upgrade can be pursued in the future.

During fiscal year 2013 Authority personnel performed routine inspections on each of the combustion-turbines. The Authority also uses a technical services contract with the OEM to assist with inspections and maintenance work. Under this contract the OEM provide a full time technical assistant (TA) during class C inspections and for the replacement parts needed in the hot gas path during class C inspections of the combustion turbine. These services have been extended through the next eight class C inspections. The Authority's employees are responsible for the installation of the replacement parts. The service agreement also establishes the basis for the provision of additional technical assistance as required for scheduled maintenance. Refer to the *Maintenance* section for a description of the scope of a class C inspection.

While operating with the original blades in service, each CT experienced a failure of compressor section blades. The failures were attributed in part to the corrosive effect of airborne contaminants. The Authority replaced the media in the air intake filter houses and the OEM tested a number of sacrificial anti-corrosion/erosion coatings on compressor blades to determine the most durable coating, with the goal of up to 100,000 hours of protective service for the compressor blades. Based on the OEM's analysis and recommendation, blades with the special coating were installed in the first ten rows of the compressor section of Unit 3. With the completion of a class C inspection of Unit 3 early in fiscal year 2009 the coated blades were installed in all three Cambalache units. The coated blades have been reliable since the 2009 installation. With the new blades the Authority no longer performs online compressor section washings. Compressor section cleanings are now done twice a year with the unit off line. The OEM has also recommended that the Authority synchronize each unit to the System and operate it at 50 MW for a period of a half to one hour each week.

The station's air permit establishes the maximum firing rate of distillate fuel oil at 104 gallons per minute per unit. Adherence to this fuel oil consumption rate impacts the capacity of these units. The amount of the limitation is subject to ambient air temperature. Higher air temperatures decrease a unit's power output while cooler temperatures, only rarely experienced in Puerto Rico, increase power output. On June 30, 2013 the one CT that was available was limited to 77 MW. Typically a CT would be limited to 80 MW indicating a 2.5 MW limitation.

During fiscal year 2013 work was deferred completing the rehabilitation of the main crane shared by the units; this work is approximately 70% complete. With the main crane unavailable the Authority has

used rented mobile equipment to service equipment. The Authority has a program to install fire suppression systems in all three units. Included in these projects are the replacement of the CO2 fire suppression system's controls, replacement of corroded piping, and the replacement of components of the foam fire suppression system. The CO2 system provides protection to the enclosed turbine areas; a foam system provides fire suppression at the storage tanks. At the end fiscal year 2013 the progress on this work was 60% for Unit 1, 85% for Unit 2 and 10% on Unit 3.

The CIP for the Cambalache plant includes $2.5 million for the scheduled "C" inspection of Unit 2 in fiscal year 2014; CIP budgets for fiscal years 2015 – 2018 have been deferred pending resolution of the availability of natural gas to the site.

Please refer to the *Maintenance* section above for a full description of what constitutes a class "A", "B", and "C" inspection referred to in this section.

CCTP Unit No. 1 (nominal 82.5 MW) was out of service for all of fiscal year 2013 due to a failure in the hot gas path during startup in September 2011. While the unit was in stable startup, a control system fault allowed high pressure steam from the OTSG to cause a flameout in the combustor, followed by an attempted re-ignition; the unburned fuel from the failed restart subsequently exploded. The explosion caused severe damage to the combustor and damaged rows of blades and a bearing in the compressor section. The OEM updated its control cards to prevent recurrence of this fault and these new control cards were installed in all three Cambalache turbines.

The OEM made an initial inspection of the damaged combustion turbine, confirmed by a more detailed inspection and submitted a quotation for repair parts and services. The OEM also provided the recommended procedures for long term preservation of the turbine which the Authority are following, pending final disposition of the matter.

CCTP Unit No. 2 (nominal 82.5 MW) was unavailable for service on June 30, 2013 while a class C inspection was being performed. During fiscal year 2013 this CT was available 90% of the year, it was in service 496 hours and had no unit trips.

The only forced outages occurred twice in February and were caused by fuel system problems; each outage lasted less than four hours.

Unit 2 began its scheduled class C inspection in late May and is scheduled to extend 60 days, in part because the Authority will avoid premium time labor for this work, which is consistent with the Authority's current policy on scheduled outages. In addition to the routine scope of the class C inspection the Authority plans to replace an air cooled auxiliary heat exchanger, rebuild the exhaust gas duct upstream of the OTSG, replace the hot gas exhaust housing with that from Unit 1 and rebuild sections of the roof and doors.

The next scheduled inspection for Unit 2 will be a class A late in fiscal year 2015, based on the current operating level.

For fiscal year 2013 this CT generated an average of 69 MW and had an annual capacity factor of 5%.

CCTP Unit No. 3 (nominal 82.5 MW) was available on June 30, 2013 but limited to 77 MW based on ambient conditions, as discussed above. During fiscal year 2013 this CT was available 99% of the annual hours, it was in service 452 hours and had no unit trips.

There were two maintenance outages in fiscal year 2013 that totaled less than two days duration. In February the Authority replaced the battery charger for the instrument DC power supply. In April the compressor section was washed off line.

The class A inspection scheduled for mid-year fiscal 2013, was rescheduled to the first quarter of fiscal year 2014 based on its accumulated equivalent operating hours. Work on the fire suppression system is scheduled during the class A inspection. The current projections are that Unit 3 may be ready for a class C inspection late in fiscal year 2015, however, the Authority plans to defer the class C inspection until the equivalent operating hours meet the criteria discussed in the *Maintenance* section above. The CIP for fiscal years 2014 through 2018 does not include funds for this inspection.

In fiscal year 2013 Unit 3's average generation was 67 MW and its annual capacity factor was 5%.

Other Combustion-Turbine Power

The Authority has a total 26 combustion turbines operated in simple cycle, i.e. they do not have exhaust heat recovery for steam production and power augmentation as utilized at Cambalache. The oldest machines are nine Combustion-Turbine Power Blocks, each with two simple cycle machines. In fiscal year 2009 the Authority installed four pairs of aero-derivative combustion turbines at the existing Mayagüez plant; they are configured with each pair driving a common power generator. In the paragraphs that follow the terms combustion turbine and gas turbine are synonymous; these machines are identified as GT, in accordance with the Authority's convention.

The original eighteen gas turbine units went into service between 1971 and 1973, are located at seven sites and have an aggregate capacity of 378 MW. They are distillate-fired Frame 5 gas turbines, each capable of generating 21 MW. These old units are in service only occasionally. The eight new aero-derivative combustion turbines installed in the Mayagüez plant replaced four of the Frame 5 GTs that had been in service at the plant since 1972. The new GTs provide the Authority with 220 MW of capacity at Mayagüez and increased the System's total simple cycle combustion turbine capacity to 598 MW. The Authority has offered two of the redundant Frame 5 GTs from Mayagüez for sale and is using two for spare parts. Twenty-one of the GT units were in service during the past fiscal year and were available for service on June 30, 2013. For fiscal year 2013 the GTs had a combined equivalent availability of 77%.

While the total net generation of the GTs during fiscal year 2013 was almost twice that of the previous year, the GTs contributed only 0.6% of the total System's net generation. During fiscal year 2013 the Mayagüez aero-derivative units accounted for 91% of the net generation of all GTs, which was consistent with recent years. The Mayagüez units have a heat rate approximately 30% lower than the older Frame 5 gas turbines and were dispatched more frequently. However, due to low System-wide demand and the availability of lower cost generating capacity, the Mayagüez units only achieved a capacity factor of 6% while recording an EA of 78% for fiscal year 2013.

The availability of the Mayagüez units was reduced in the past year because the four turbines comprising Units 1 & 2 require replacement and modifications to the turbine first stage blade and seals at the OEM mainland shop. The four turbines in Units 3 & 4 had been modified during production. While at the factory the OEM is installing upgrades under warranty. The Authority has rotated one turbine at a time for the repair; by the end of fiscal year 2013 two were upgraded and in service, one was in the OEM's shop being prepared for shipment back to the island and the last was scheduled to be sent to the OEM in early calendar year 2014. In the past fiscal year Unit 3B's control system software was updated under warranty for improved vibration sensor processing, all the other Mayagüez units will share the control system updates. The CIP for fiscal year 2014 for the plant includes funds for replacing the electrodeionization (EDI) water demineralizers that have been unreliable recently. High purity water is required since it is injected to reduce NOx but must not leave deposits in the turbine.

All of the Frame 5 gas turbines combined were in service less than half the hours of the Mayagüez units during fiscal year 2013. Of the Frame 5 GTs that operated in the past fiscal year, the average annual service was less than 100 hours. Consequently these turbines have accumulated equivalent operating hours at a low pace and scheduled inspections have been adjusted. The Authority has continued routine operation in which engineers perform preventative maintenance tests and inspections of GTs at prescribed weekly and monthly intervals.

The Authority's CIP includes $3.3 million for planned inspections of the Mayagüez turbines for the five fiscal years 2014 through 2018. The CIP also allocates $12.2 million for three major inspections of GTs in the same period. The scope of planned work includes completion of the program to install new fire suppression systems at the combustion turbine sites.

Since the Authority relies on the GTs to provide reliable power it is essential that their diesel starting systems be in good operating condition. As discussed below the Authority has repaired or replaced three of the diesel motors in the last two years in the 18 Frame 5 GTs.

Jobos 1-1: During fiscal year 2010 the Authority completed an intermediate inspection of this GT. As part of the inspection the generator rotor was rewound in a mainland shop. While conducting pre-acceptance testing late in fiscal year 2010, the generator's rotor vibrated excessively possibly caused by crossed windings. During fiscal year 2012 the rotor was removed, inspected and balanced on site by the contractor under warranty. In fiscal year 2013 the GT was reassembled. It is scheduled for testing prior to its return to available status in fiscal year 2014.

Daguao 1-2: The Authority completed a major overhaul of this unit during fiscal year 2012. Its generator stator was rewound and the generator's rotor replaced, a new excitation system and a Mark VI turbine control system were installed. The turbine and compressor sections were replaced, as was the ratchet and torque converter. The GT was repainted. During testing the Authority encountered problems with the turbine control system and with the diesel motor. The diesel motor was replaced and the control system was tuned. An electrical fault in one phase of the station power output delayed returning the unit to available status, which is forecasted for fiscal year 2014.

Aguirre 2-2: This GT did not operate in fiscal year 2013. During preventative maintenance testing the diesel motor failed late in fiscal year 2012. The Authority has hired a local firm to repair the diesel motor, along with one for Palo Seco 1-1. This unit is expected to return to available status at the end of the first quarter of fiscal year 2014.

Palo Seco 1-1: The diesel motor failed in the second quarter of fiscal year 2012. Since the Palo Seco GT units have a backup power feed directly from the adjacent Palo Seco Steam Plant, the loss of a starting diesel is less disruptive for these units than others. Nevertheless the Authority sent the failed diesel to the same repair shop as the Aguirre 2-2 motor. This unit is expected to return to available status at the end of the first quarter of fiscal year 2014.

Vega Baja 1-1: This unit was unavailable for more than half of fiscal year 2013 to replace turbine bearing number 1. The GT returned to available status for the last two months of the past fiscal year.

Hydro Production Plant

Total Generating Capacity 100 MW

The Authority has 21 hydroelectric generating units at eleven locations. They have an aggregate capacity of 100 MW. The Authority reported that for fiscal year 2013 the hydroelectric generating units had an aggregate equivalent availability of 63% and generated 90,900 MWh, which was 73% of their net generation during fiscal year 2012 and 61% of their output in fiscal year 2011. The hydroelectric units had an annualized service factor of 10% in the past fiscal year. Recent power generation from the hydroelectric plants has been constrained in part by low rain fall and accumulating sediment that compromises the useful capacity of reservoirs.

On June 30, 2013 the hydroelectric system was capable of generating 43.5 MW. Thirteen of the 21 units were reported as available for service. Two of these, the Patillas units with a combined capacity of less than two megawatts, have not been in service for more than eight years. Budget constraints have lengthened the time to repair units and return them to available status; this was most evident following a forced outage event. Sixteen units were forced from service; on average each of these units accrued a total of 3,012 forced outage hours during fiscal year 2013, which was 15% less than the previous year. Five of the 21 units were scheduled from service for maintenance and scheduled inspections during fiscal year 2013. These outages accumulated 4,800 hours, that total was one-tenth of those for the forced outages. As discussed below, the Authority's largest hydroelectric unit, Yauco 1, was dispatched at less than half of its rated 25 MW capacity during the 1,921 service hours that it accrued during the fiscal year. The three units at Dos Bocas averaged 2,282 hours each in service which was the most of all the Authority's hydroelectric plants in fiscal year 2013. Housekeeping at the hydroelectric stations was uniformly good, logbooks were well maintained, inspections, and operational data were well documented. Preventative maintenance activities were completed at specified intervals.

During fiscal year 2013 the Authority spent $1.8 million on capital rehabilitation improvements of existing hydroelectric facilities. The Capital Improvement Program includes $3.2 million for the refurbishment of hydroelectric units in fiscal year 2014; a portion of the fiscal year 2014 CIP budget will be directed to ongoing work carried forward from the previous fiscal year. From fiscal years 2015 through 2018, however, the CIP includes significant budget increases for capital projects at hydroelectric facilities. A total of an additional $11 million is allocated for rehabilitation projects and $13 million is budgeted for partial dredging of the sedimentation in Dos Bocas reservoir which feeds the Dos Bocas and Coanillas hydroelectric plants. The low level of funding in the past two years forced planned inspections to be delayed and increased the potential impact of a critical equipment failure or unplanned event on the corresponding unit's availability and capacity. These impacts will be diminished as the scheduled improvements are performed.

The following is a brief discussion of work at hydroelectric plants during during fiscal year 2013:

Caonillas 1-1: With a design capacity of 9 MW the unit experienced excessive turbine vibration when operating above 6 MW. These vibration issues arose following the forced outage of Caonillas 1-2. The unit was removed from service for inspection in fiscal 2012. The Authority has identified improvements in the controls which should resolve the instability. These new controls were ordered for both Caonillas units in fiscal year 2013. Delivery and installation of the improved controls is scheduled for fiscal year 2014.

Caonillas 1-2: The Authority found water leaks at the wicket gates of this 9 MW unit in April 2011. Repairs were completed before the end of the past fiscal year, however, the unit did not return to service during fiscal year 2013, pending installation of the new control system discussed above.

Caonillas 2-1: This unit's 3.5 MW of capacity has not been available since Hurricane Georges struck the Commonwealth in 1998 and filled Lake Vivi with sedimentation. The current five year CIP does not fund the removal of the sedimentation making a return to available status unlikely in the foreseeable future.

Garzas 1-1: This 5 MW unit was unavailable for service during fiscal year 2013. It was forced from service in fiscal year 2012 when the generator's excitor failed. The contract award for the replacement excitor was contested; the procurement process was repeated. The rewound generator is scheduled to be returned in the first quarter of fiscal year 2014.

Rio Blanco 1-1 & 1-2: Each unit is rated to be capable of generating 2.5 MW; they both were forced from service in fiscal year 2012 by breaks in the penstock and did not return in the past fiscal year. Penstock repairs were completed, but the penstock supports had not been tested and accepted by the end of fiscal year 2013. While these repairs were in progress the Authority sent the two generator rotors out for inspection, repair, and rebalancing. Both rotors were returned at the end of fiscal year 2013. The units are scheduled to return to available status during the third quarter of fiscal year 2014, after the integrity of the penstock has been confirmed.

Yauco 1: With a design capability of 25 MW, this is the Authority's largest hydroelectric unit. The water passing through the unit is used for irrigation. Damage to turbine nozzles, the turbine, and other mechanical components have limited its capacity to 10-12 MW for the past several years. In preparation for the unit's overhaul a water bypass system was installed during fiscal year 2011. The bypass system's discharge lines were modified during fiscal year 2012 and testing of the bypass system began late in the fiscal year. During testing the Authority determined that the bypass control valve was undersized and filed a claim against the design contractor for the replacement of the valve with one of the appropriate capacity. In fiscal year 2013 the Authority solicited bids for the replacement bypass control valve, but the order is not scheduled to be placed until fiscal year 2014. The schedule for further work on the repairs is subject to the bypass system demonstrating safe operation. Also during fiscal year 2012 the tunnels bringing water to the station were inspected and new trash rakes were installed. Trash removal continued in fiscal year 2013. To reduce the overhaul cost the Authority plans to replace the most severely damaged turbine buckets with spare buckets that the Authority has in storage, the scope also includes replacement of several turbine bearings, and miscellaneous repairs. Once the safe operation of the bypass control valve is assured, the Authority estimates the repairs can be performed in less than a year.

Yauco 2-1 & 2-2: Although the Yauco 2-1 was available 6,861 hours in the past fiscal year, its generator exciter needs repair or replacement. The Authority may defer this work until fiscal year 2016 when it plans to refurbish both units. The schedule of the overhaul is dependent on installing new main isolation gate valves for the units.

Diesel Generators

The diesel generators installed by the Authority on the islands of Vieques and Culebra provide backup power in the event of an interruption of the power delivered by submarine cables to these islands.

During fiscal year 2012 the Authority began work to replace the four diesel generators on Culebra, with a combined capacity of 2.0 MW, with three new 2 MW diesels. The first step was the installation of a temporary back-up 2 MW diesel generator to provide emergency generation while the replacement of the four small diesels was in progress. During fiscal year 2013 the temporary diesel was in service a total of 14 hours and generated 5 MWh. The three 2 MW diesel generators are scheduled to be installed on Culebra in fiscal year 2014. Site development, erection of the fuel storage tank and other work that will precede the installation of the new units continued during the past fiscal year. The new units bring 6 MW of capacity to Culebra and are scheduled to enter service late in fiscal year 2014. Following their commissioning the Authority will remove the temporary 2 MW diesel generator that provided emergency capacity while the three new diesel generators were being installed. Expenditures on this project were $770,000 in fiscal year 2013, with the budget of $2.5 million in the CIP to complete.

On Vieques the Authority's two 3 MW diesel generators were in service a total of 28 hours during the fiscal year and generated 49 MWh while in service. During the last fiscal year the Authority installed replacement control systems for the two diesel generators on Vieques. The replacement system has an open architecture for ease of troubleshooting which will expedite repairs.

FUELS

Since March 2007 the Authority has been burning a residual fuel oil with a sulfur content not exceeding

0.5% by weight in all of its large steam electric generating stations. Following the switch to the low sulfur fuel, the two stations on the south side of the island discontinued the use of fuel additives. In fiscal year 2009 the Authority revised its distillate fuel specification and since making the revision has been burning a distillate fuel oil with a sulfur content not exceeding 0.05% sulfur in its simple and combined cycle units. This standardization has helped the Authority to realize better pricing and supply options.

The Authority's standard practice for the supply of fuel oil is based on one-year contracts with the option of extending the contract for an additional year or less. The fuel oil pricing is structured on the commodity market with a fixed adjustment to account for delivery to Puerto Rico and the local delivery requirements of smaller barges for the plants on the north coast. The Authority selectively employs different strategies to minimize the commodity price volatility in these contracts; these strategies include fixed price contracts and commodity hedges.

During the first two months of fiscal year 2013 residual oil was supplied to the Aguirre Steam Plant in completion of a six-month contract that went into effect on the first of March 2012. A four-month contract to another supplier was effective as of September 1, 2012 and was in effect until the end of calendar year 2012. The Authority placed a one-year contract with a third supplier for the supply of residual fuel oil for the Aguirre and Costa Sur steam electric units beginning in January 2013. This contract is in effect through calendar year 2013, with a four month extension clause. The Authority has three residual oil storage tanks at Aguirre, each with a capacity of 260,000 barrels. The Aguirre units typically receive 70,000 barrels of residual fuel oil every three days. During fiscal year 2013 these units consumed an average of approximately 21,700 barrels per day (BPD) of residual fuel oil when both were in service.

The contracts for the supply of residual oil to the Costa Sur Steam Plant followed the same sequence as the Aguirre Steam Plant outlined above. Units 5 & 6 are the dominant production units at Costa Sur and have been converted to burn natural gas, as discussed in the *Capacity and Energy Resource Planning* section. Since the Authority plans that natural gas will be the principal fuel in these units their consumption of residual fuel oil will be less than previously. The Authority has 800,000 barrels of residual oil storage capacity at the Costa Sur Steam Plant. The station receives 250,000 barrels of residual fuel oil every two to three weeks. On average these units consumed approximately 10,100 BPD of residual fuel oil when in service during the past fiscal year.

The one-year contract for the supply of residual oil for the Palo Seco and San Juan Steam Plants that was awarded in January 2013 includes an option for a four-month extension. As described above, prior to awarding this contract the Authority placed a four-month contract with a different supplier for the supply of residual fuel oil to these plants through the end of calendar year 2012. At the Palo Seco Steam Plant the Authority has the capacity to store 450,000 barrels of residual oil; at the San Juan Steam Plant there is an additional 138,000 barrels of storage capacity for residual fuel oil. These stations receive a combined total of 250,000 barrels of residual fuel oil every ten days. Over the course of the full year these stations consumed a combined average total of 22,400 BPD of residual fuel oil in fiscal year 2013.

The Authority's contract for the supply of natural gas to the Costa Sur Plant is for two years and runs through April 30, 2014. The gas is supplied from the gasification facility at the EcoEléctrica cogeneration plant adjacent to the Costa Sur Plant. The quantity of gas available gas under this contract will meet the combined consumption of Units 5 & 6 firing only gas with a capacity factor of approximately 60%. The Authority plans to restructure and rebid this contract during the next fiscal year.

The Authority's contracts for the supply of distillate specify that the distillate not contain more than 0.05% sulfur by weight. In July 2012 the Authority awarded a contract for the supply of distillate fuel to the Cambalache and Mayagüez gas turbines, and to the combined cycle units at Aguirre and San Juan. The contract is in effect for one year and does not include the option for an extension. Distillate fuels are delivered to a south coast storage facility and from there are barged to each of the four stations. During fiscal year 2011 the CAPECO facility was acquired by Puma Energy Caribe; remediation work and restoration of fuel storage capacity is progressing. A portion of the restored storage capacity for distillate fuel oil could be available to the Authority during fiscal year 2014.

The Authority has not entered into a long term contract for the supply of distillate fuel oil for the Authority's Frame 5 gas turbines. As discussed in the *Other Combustion Turbine Power* section, these units are located in nine power blocks around the island and they accumulated very few service hours in the past year; because of their high production costs they are forecasted to remain backup power capacity. In

practice the fuel consumption at each Frame 5 gas turbine block requires only an infrequent truck delivery of distillate fuel oil, which is paid based on the market price at delivery.

BATTERY ENERGY STORAGE SYSTEM

The 20 MW Battery Energy Storage System, BESS, at Sabana Llana was commissioned in August 2004. The plant was designed to provide ready reserve capacity in response to a System disturbance and power factor correction when needed. The plant consisted of two units, 1A and 1B, each with more than 3,000 batteries. Within two years of commissioning a fire in the batteries of one unit forced it from service. The Authority alleges that design faults with the batteries caused the fire, consequently neither unit was returned to service.

Since 2008 the parties have engaged in complex litigation with extended discovery. In succession the battery manufacturer, its Puerto Rican partner, and most recently the bonding company have all failed and declared bankruptcy. The litigation continues, however, it is unlikely that there will be much recovered. The Authority continues to evaluate the future use for the BESS building as well as the salvage value of the more than 6,000 batteries and the associated obsolete electronic gear.

SPARE COMPONENTS

To reduce the unscheduled outages of various units, the Authority has purchased a number of critical spare components (see the following list). Using such spare components during an emergency outage has expedited a unit's return to service. Once the damaged component is repaired, it becomes the spare. This practice has significantly reduced the downtime of some of the Authority's large units thereby helping to maintain both unit and System availability.

The value of these spares is included in the value of the Authority's inventoried equipment and material reported in the *Inventories and Other Properties* section.

The following is a list of major spare components:

- HP/IP and LP turbine rotors for Aguirre Unit Nos. 1 & 2
- HP/IP and LP turbine rotors & diaphragms for Costa Sur Unit Nos. 5 & 6
- Generator rotor for Aguirre Unit Nos. 1 & 2
- Motors for FD, ID, GRF, & air heaters for Costa Sur Units Nos. 5 & 6 and Aguirre Unit Nos.1 & 2
- Normal Station Service Transformer adaptable to Costa Sur Units Nos. 5 & 6 and Aguirre Unit Nos.1 & 2
- Motors and pumps for condensate, boiler circulating, & boiler feed water for Costa Sur Unit Nos. 5 & 6
- Emergency Station Service Transformer for Aguirre Steam Station
- LP turbine rotor for Palo Seco Unit Nos. 3 & 4
- Generator rotor for Palo Seco Unit Nos. 1 & 2
- Main Power Transformer for Palo Seco Unit Nos. 3 & 4
- CT generator rotor for the Aguirre Combined-Cycle Plant
- CT turbine rotor for the Aguirre Combined-Cycle Plant
- Main Power Transformer for Aguirre Combined Cycle Station
- Two generator rotors for the Frame 5 gas turbines
- Compressor rotor assembly for a 21 MW gas turbine
- Service transformer for San Juan Station Units
- Replacement motors for all large pumps
- Replacement rotors for FD, ID, & GRF fans
- Large pumps and vacuum equipment for combined cycle & steam-electric units
- Burners, soot blowers, air heater components for steam-electric units

PRODUCTION PLANT CAPITAL IMPROVEMENTS

Production plant capital expenditures in fiscal year 2013 amounted to $148.3 million. As shown in *Appendix VI, Capital Expenditures*, production plant capital expenditures in millions are forecasted to be $96.4, $115.9, $110.4, $128.5, and $124.7 in fiscal years 2014 through 2018 respectively. Details by Budget Item Number for these five fiscal years are shown in *Appendix X, Details of Capital Improvement Program.*

ENVIRONMENTAL

The Environmental Protection and Quality Assurance Division is responsible for assisting the Authority's operating directorates to comply with applicable Federal and Commonwealth environmental laws and regulations. These responsibilities include the development of comprehensive programs to achieve the Authority's environmental performance goals. This division is charged with obtaining the permits required to increase or modify any Authority owned capacity assets prior operating within the System.

In December 2011 the EPA signed regulations under the Clean Air Act (CAA) that reinforced the Authority's long standing objective to maximize the utilization of natural gas in its generating units. While the Authority's principal objectives have been fuel diversity and lower cost, natural gas has the beneficial feature of being a much cleaner fuel than residual oil. The EPA regulations established new national emission standards for hazardous air pollutants under the mercury and air toxics standards (MATS). These regulations apply to certain solid waste incinerators and large commercial and industrial boilers; these are principally coal and oil fired steam electric generating units larger than 25 MW. The pollutants subject to regulation are heavy metals, including mercury, arsenic, chromium, nickel and acid gases such as hydrogen chloride and hydrogen fluoride, sulfur dioxide, and also particulate matter and carbon monoxide. If pollution abatement equipment is required to reach the mandated emission levels of these hazardous air pollutants, the EPA will require the installation of up to the maximum achievable control technology (MACT), which is based on the best demonstrated performance technology regardless of cost. The MACT for the Authority's units could consist of various retrofitted emission control systems, such as filter baghouses and flue gas desulfurization equipment and associated ancillary systems. The high cost and restricted space at most steam plants make this approach impratical.

Since compliance with MATS will be established on the basis of individual units, the Authority's compliance strategy is to convert its eight largest oil fired steam generating units to dual fuel firing, burning natural gas fuel in addition to or in place of oil, and to restrict the operation of the remaining six steam units to 8% capacity per year to qualify as limited use liquid oil fired generating units (LULOF). The EPA's initial schedule for the implementation of MATS requires compliance by April 2015, with two one-year extensions potentially available. The Authority plans to request some extensions since the necessary gas supply infrastructure will not be in place by April 2015 to support gas firing at all eight of the steam units.

The Authority's current strategy to expand the supply of natural gas on the island has been an offshore gasification facility for LNG deliveries near its Aguirre power complex on the southeast coast. During fiscal year 2013 the Authority continued its due diligence on the contractual structure of the gas supply infrastructure and was evaluating alternative supply arrangements. Meanwhile the Authority continued to develop a coordinated air permit application for both the off-shore scope in addition to the Aguirre plants.

The Authority has focused first on its four largest steam units for dual fuel conversion—gas in addition to oil—on the south coast. The four steam units in the San Juan metropolitan area will be converted after the schedule for gas deliveries has been established. With sufficient fuel being available the Authority plans to add gas firing capability to the Authority's two most efficient units, San Juan Units 5 & 6, which are combined cycle units presently burning high cost distillate fuel.

During fiscal year 2011 Costa Sur Units 5 & 6 were converted to dual fuel burning capability. Subsequently the boiler internals were modified to support continued full load operation with all gas firing; this work was performed for Unit 6 during fiscal year 2012 and completed for Unit 5 by the end of last fiscal year. Initial stack testing with dual fuel firing has demonstrated compliance with MATS criteria. The natural gas was supplied by EcoEléctrica L.P. via a pipeline from its facility adjacent to the Costa Sur Steam Plant. During fiscal year 2013 EcoEléctrica installed and made operational two additional regasifiers. Additional regasification production is possible with the installed equipment, however this would require a revised permit from the Federal Energy Regulatory Commission (FERC).

During fiscal year 2013 the Authority performed environmental protection or environmental remediation projects at each of its major generating stations and at numerous transmission and distribution facilities. Environmental projects performed in the last fiscal year were budgeted at $8.1 million; actual 2013 expenditures were $2.2 million. The Authority's five-year capital improvement program (CIP) for fiscal year 2014 through 2018 identifies environmental projects valued at $62.8 million. During fiscal year 2014 the Authority has budgeted $12.6 million to be spent principally on modifications to cooling water systems and spill prevention projects.

In fiscal year 2014 at the Costa Sur Steam Plant the Authority has budgeted $5 million to fund section 316 (a) & (b) Clean Water Act projects; these projects address mitigation of the cooling water intake and discharge systems. The section 316 (a) & (b) projects are each budgeted to cost $27.1 million over the five years to completion in fiscal year 2018. These are the two largest and most costly environmental projects that the Authority has currently funded. After several years of work, in fiscal year 2012 the Authority completed the rehabilitation of the station's outflow channel walls which was another environmental project at the Costa Sur Steam Plant.

The Authority has pursued a long term program to refurbish its large fuel oil storage tanks and containment dikes at all its steam electric plants. In fiscal year 2013 it has budgeted $1.1 million for the refurbishment of fuel storage tanks at the San Juan Steam Plant. The refurbishment of the fuel storage capacity at the Aguirre and Costa Sur Steam Plants is scheduled to continue through fiscal year 2017; at a budgeted cost of five million dollars.

Although the Authority has had an active asbestos abatement program for decades some equipment and facilities still have asbestos containing material which has been secured until such time when maintenance activities require its removal; $1.5 million of the environmental program budget for fiscal year 2014 is dedicated to asbestos remediation projects. These projects enable the Authority to reduce exposures to and release of asbestos containing materials through encapsulation and removal. The abatement work takes place during programmed outages such as the major overhaul of a steam unit.

Since discovery in 1997 of oil contaminated soil at the Palo Seco Steam Plant and in the area of the Palo Seco Warehouse, the Authority has taken steps to remediate contamination from oil with a low concentration of PCB that was found in monitoring wells; this work included investigations and removal of contaminated soil. Based on a letter notice from the EPA in December 2011, further investigation and remediation activities at this site will not be required pending submittal of the Authority's final report and acceptance by the EPA. The Authority expects the conclusion from the EPA during fiscal year 2014.

The Authority has a program to comply with Spill Prevention Control and Countermeasures (SPCC) regulations regarding containment of potential leakage from oil containing electrical equipment in its distribution substations. During fiscal year 2011 the Authority completed the installation of signage and spill response material at all its substations. By the end of fiscal year 2013 it had completed the construction of compliance containment at 42 of the 58 substations that need to be upgraded and will complete the balance during fiscal years 2014 and 2015.

The Authority completed a program many years ago to remove from service and dispose of all of its transformers and electrical equipment with PCB concentrations greater than 499 ppm. Since then the Authority has continued with a long standing program to remove transformers with oil containing PCB between 50-499 ppm. The Authority has cataloged less than two hundred remaining transformers for removal. All of the transformers and electrical equipment with PCB concentrations greater than 499 ppm were removed from service and disposed of years ago.

In February 1992 the EPA conducted a multimedia inspection of the Authority's four steam electric power plants (Aguirre, Costa Sur, Palo Seco, and San Juan) and the Monacillos Transmission Center. In December 1992, the EPA identified several instances of noncompliance related to air emissions, water discharges, and to the Spill Prevention Control and Countermeasure (SPCC) compliance program at the Authority's four major steam electric generating stations and at the Monacillos Transmission Center. These findings led in March 1999 to an agreement between the agencies of the federal government and the Authority, which became the basis for the court approved Consent Decree, which while subsequently amended, is still in effect. The Authority agreed that starting in March 2003 the residual fuel oil burned in the steam electric generating stations at Palo Seco and San Juan on the north coast of the island would have a sulfur content not exceeding 0.5% by weight. Since March 2007 the Authority has been burning a fuel oil with a sulfur content not exceeding 0.5% by weight at its south coast steam electric generating stations at Aguirre and Costa Sur. For more discussion on this refer to the *Fuels* section of *System's Operations*. During fiscal year 2007 the Authority completed projects to reduce NOx emissions at steam electric generating stations at Palo Seco, Aguirre, and Costa Sur. As a condition of receiving certain permits the units at San Juan Station had previously been modified to reduce NOx emissions. The Authority and the EPA monitor compliance with the lower NOx emissions requirements.

During the past fiscal year the Authority reported achieving compliance in excess of 99% with its in-stack opacity requirements and with its Air Quality Compliance Program and also achieving the same high level of compliance with Clean Water Act regulations. At the end of fiscal year 2013 none of the Authority's generating stations was on probation with the EPA. There were no events, leaks or spills reported during fiscal year 2013 that could lead to significant administrative action.

COGENERATORS

The Authority has entered into long-term Power Purchase Operating Agreements (PPOAs) with the owners of two cogeneration plants in Puerto Rico. These plants, one fueled by natural gas (vaporized LNG) and the other by coal, bring fuel diversity to the island's generation mix. The Authority's PPOAs with the cogenerators establish the technical and commercial principles under which they mutually operate.

These include the methods for calculating the capacity and energy costs of the delivered power, which are adjusted for a twelve-month period at the start of each calendar year. The plants incorporate emission control technologies enabling them to comply with current environmental standards; both plants are highly efficient. The Authority controls the dispatch of the cogenerators' power. During fiscal year 2013 the cogenerators accounted for 33.7% of the System's net generation, up from the 31.3% in the preceding fiscal year. (For further discussion of these power producers see the *Capacity and Energy Resource Planning* section)

The Authority treats its purchased power costs as an operating expense in its various financial schedules and recovers them from its clients utilizing a purchased power charge similar to its fuel charge. The Authority's purchased power costs from the cogenerators were $735.1 million in fiscal year 2013. The amount of $755.7 million shown in *Appendix III, Detail of Operating and Maintenance Expenses,* for purchased power includes the renewable energy project. For fiscal years 2014 through 2018 the Authority's forecasts of purchased power include the costs and power contributions from additional renewable energy projects coming on line as discussed in the *Capacity and Energy Resource Planning* section coming on line. The Authority, however, projects that the cogenerators will be the largest sources of purchased power through fiscal year 2018. As shown in *Appendix IV, Annual Net Generation, Fuel Consumption, Fuel and Purchased Power Costs,* during the five year period beginning with fiscal year 2014 the Authority forecasts the costs of cogenerator sourced purchased power in millions of dollars will be $702.8, $732.5, $759.8, $789.2, and $817.9, respectively.

EcoEléctrica, L.P.

On March 21, 2000, the Authority began buying 507 MW of power from EcoEléctrica, L.P. in accordance with a 22-year PPOA. The plant consists of two combustion-turbines (CTs) each with a heat recovery steam generator (HRSG), i.e., boiler, combining to power a single steam turbine-generator, STG. Each of the CTs is capable of generating 167 MW; the steam turbine-generator is capable of generating 173 MW. The plant's waste heat is used in a desalinization plant capable of producing 2 million gallons of fresh water a day. The water is for its own use and for sale to the Puerto Rico Aqueduct and Sewer Authority and the Authority for its use at the Costa Sur plant. The EcoEléctrica, L.P. complex also includes an LNG unloading dock, an LNG storage tank, LNG vaporizers, and associated facilities.

In accordance with the PPOA each calendar year EcoEléctrica fixes the fuel cost per million BTU for the first 76% of the station's capacity for that year. For capacity in excess of 76% the Authority has been charged based upon a spot fuel price that was set by EcoEléctrica at the time the excess capacity was dispatched. From time to time the Authority has agreed to purchase power at a capacity above the facility's nominal rating of 507 MW, however power purchases at these levels has not been formally incorporated in the PPOA.

The EcoEléctrica plant is located in close proximity to the Costa Sur generating complex and a gas pipeline from the EcoEléctrica facility has been installed to the Costa Sur plant. The Authority has contracted with EcoEléctrica to store and regasify LNG in sufficient quantity to supply the Authority with natural gas for the Costa Sur Units 5 & 6 which have been converted to dual fuel capability. To supply sufficient natural gas for itself in addition to Costa Sur Units 5 & 6, EcoElectrica has installed two new regasifiers in addition to the existing two. Of the two regasifiers initially commissioned for service, one was needed to regasify LNG for EcoElectrica's two combustion turbines and the second regasifier was a full spare backup that would be used if the other regasifier were not available. To satisfy the Authority's need for natural gas at Costa Sur and have spare capacity, EcoEléctrica installed two additional LNG regasification units during fiscal year 2012. While EcoEléctrica then had four regasification units, they did not have FERC's approval to put more than one additional regasifier into continuous service. Under the present FERC permit the third and fourth regasifiers are spares and a permit revision would be required to increase the number of LNG ship deliveries per year or the number of regasifiers in concurrent operation; this scenario could be associated with increased gas utilization by EcoEléctrica at its facility or expanded gas firing by the Authority at the Costa Sur plant. Based on projected demand and System dispatch, the gas supply from two regasifiers will support both of the large Costa Sur units firing 100% with gas, in addition to the EcoEléctrica units. If additional power is required from Costa Sur Units 5 & 6, these units can use residual oil in conjunction with natural gas or as the only fuel, within the limitations of the air permit criteria.

For fiscal year 2013 EcoEléctrica achieved an equivalent availability of 91.4%, considerably lower than the

equivalent availability of 95.0% achieved during fiscal year 2012, and less the contractual target of 93%, consequently reducing EcoEléctrica's capacity payments. Although the plant's availability dropped during the past fiscal year, its annual capacity factor increased from 77% to 80% while generating 4.3% more energy in fiscal year 2013 than in fiscal year 2012.

CT 1 was scheduled out of service twice and forced out three times during fiscal year 2013. The scheduled outages totaled ten days, while the unscheduled accrued 16 days. The first scheduled outage in January was for six hours to isolate from the steam turbine which was beginning its major inspection. In February this combustion turbine was out for ten days for its scheduled annual maintenance. The combustion turbine was out of service for two days in August to resolve high temperature differential in a combustor. In September it was unavailable for six hours due to a failure in an LNG pump. The last of the three unscheduled outages was for almost 14 days to resolve problems with the generator stator.

CT 2 was scheduled out of service twice and forced out four times during fiscal year 2013. The scheduled outages totaled 15 days, while the unscheduled accrued eight days. The first scheduled outage in January was for seven hours to isolate from the steam turbine which was beginning its major inspection. In February this combustion turbine was out for 15 days for its scheduled annual maintenance. The combustion turbine was out of service for seven hours in July to repair a loose connection on protective relays for one phase of the generator. In September it was unavailable for eight hours due to a failure in an LNG pump. In October this combustion turbine was out for four hours to repair damaged fuel tubing at a combustor. The last of the unscheduled outages was for almost seven days to resolve the same problems with the generator stator as applied to CT 1.

ST During fiscal year 2012 this 173 MW steam turbine was fully or partially unavailable for approximately 43 days; 32 of which accrued during a scheduled major inspection beginning in January. During the inspection the steam turbine valves were cleaned and inspected. The turbine internals were refurbished as necessary. Preventative maintenance was completed on unit auxiliaries. The steam turbine was unavailable for an additional eight days following the inspection to rebalance the rotating elements to resolve high vibrations. The loss of an LNG pump in September that took out both combustion turbines forced the steam turbine out for seven hours. The steam turbine also accrued several equivalent outage hours associated with the forced outages for CT 1 in August and CT 2 in October discussed above.

In fiscal year 2013 EcoEléctrica provided 17.0% of the System's power, exceeding the Authority's forecast of 15.3% of the System's net generation during the past fiscal year. The Authority forecasts that EcoEléctrica, L.P. will generate 17.5% of the power sold by the Authority during fiscal year 2014.

AES-PR

AES-PR's coal-fired steam-electric cogeneration station began commercial operation in November 2002. The owners of the facility have entered into a PPOA with the Authority to provide 454 MW of power for a period of 25 years. The station is made up of two similar units; each is comprised of a circulating fluidized bed steam generator employing clean coal burning technology and a steam turbine-generator capable of generating 227 MW. AES-PR has assured the Authority that its units will readily comply with the new MATS standards, discussed in the *Environmental* section, which will apply to the coal firing plant beginning in April 2015. During fiscal year 2013 AES-PR produced 16.7% of the power sold by the Authority, compared to the 16.1% of the System's net generation that the Authority had forecast for AES-PR. The net generation by AES-PR in fiscal year 2013 was 9.5% more than in fiscal year 2012 and more than 4% above its previous five-year average. The Authority's forecast for power from AES-PR for fiscal years 2014 through 2018 are based on output comparable to the five-year average of fiscal years 2009 through 2013. For the remaining years of the PPOA's term, the plant has a target equivalent availability of 90%, a target it did not achieve in the five years preceding fiscal year 2013.

During the past fiscal year AES-PR achieved an equivalent availability of 91.1%, which was a significant improvement over the 87.4% in fiscal year 2012. The scheduled maintenance in Unit 1 was the longest outage event for the two units in fiscal year 2013. The plant achieved a capacity factor of 88.3% for all of fiscal year 2013. The Authority forecasts that AES-PR will generate 15.8% of the power sold by the Authority during fiscal year 2014.

Unit 1: was scheduled out of service once and forced out four times during fiscal year 2013. The scheduled maintenance outage lasted 27 days, while the unscheduled events accrued 25 days. Unit 1 came out of service in March at the start of its scheduled outage for annual maintenance. During the outage auxiliaries were cleaned and inspected, refractory repairs

completed; routine cleanings, inspections, and preventative maintenance was completed on burners, mechanical equipment, coal, limestone, and ash handling systems. The turbine was opened and inspected. In August this unit was forced from service for ten days to repair tube failures in the fluidized bed heat exchanger (FBHE). Two additional heat exchanger failures required repairs in February and March, accruing 12 days unavailable. In September the unit was forced from service for three days to repair the generator exciter system controls.

Unit 2: During fiscal year 2012 this 227 MW unit was fully or partially unavailable for approximately 25 days. There was no scheduled maintenance during the past fiscal year, the next is scheduled for the second quarter of fiscal year 2014. Three incidents accounted for 97% of the total equivalent lost generation for this unit in fiscal year 2013. In October the unit was out of service for six days to repair the superheater ash regulating valve. Repairs to the boiler heat exchanger forced the unit out for ten days in December. The unit's output was limited by 83 MW for nine days beginning in May because of vibration in one of the boiler feed pump hydraulic couplings. Seven other brief incidents accounted for the balance of the limitations and outage hours for the past fiscal year.

TRANSMISSION AND DISTRIBUTION SYSTEMS

The Authority's transmission and distribution systems is comprised of an island-wide network of power lines, switchyards, substations and electrical equipment that carry the electrical power from the production plants to serve the Authority's clients.

On an annual basis the Consulting Engineer's personnel visit and note the condition of approximately one-third of the Authority's 333 distribution substations and 45 transmission centers (TCs). In order to observe a representative sample, we select substations from among the 78 municipalities in the 26 districts served by the Authority. The scope of the inspections include a representative portion of the Authority's 230/115 kV transmission lines.

TRANSMISSION

The Authority's transmission system consists of high voltage power lines, switchyards and electrical equipment that carry the electrical power from the production plants to the dispersed substations, both the Authority's and privately owned substations, which serve the System load. The backbone of the transmission system is the 230/115 kV network that moves bulk power. The balance of the transmission system is the 38 kV lines and equipment that serve the whole island and also provide the submarine service to the islands of Vieques and Culebra. For reference when reading this section, a map of the Authority's 230 kV and 115 kV transmission systems precedes the Appendices. The map shows the existing transmission system with the planned modifications to the systems through fiscal year 2018.

230 kV System

The existing 230 kV system is comprised of 375 circuit miles of transmission lines that encircle and sectionalize the island. The 230 kV system has two north-south corridors which divide the system into three principal loops—the western loop, the central loop and the eastern loop. Each north-south transmission line originates at a major production facility in the south and carries power to the load centers in the north.

The central loop has been in operation for many years. It was the first 230 kV transmission line to tie the generating plants located on the island's south coast to the load concentrated in the San Juan metropolitan area via the Aguas Buenas TC south of the city. A parallel 230 kV line in the center of the island connects the Costa Sur and EcoEléctrica production units in the south with the Manatí TC located between San Juan and the Cambalache combustion turbine station on the north coast. The central loop is joined by east-west transmission lines connecting the Costa Sur units with the Aguirre plant in the south and a line on the north side of the island connecting Manatí to Aguas Buenas via Bayamón.

The western loop connects the Costa Sur and EcoEléctrica production units in the south with the Mayagüez switchyard and production units, on the west coast of the island, and from there to the northern cities of Aguadilla, Hatillo, and Arecibo. The western loop was completed in fiscal year 2002 following the construction of the segment connecting Mayagüez and the Cambalache TC. The loop increased the transmission system's capacity and reliability and improved the quality of electric service in the north-western municipalities.

The most recent expansion to the 230 kV transmission system was the eastern loop that went into service during fiscal year 2006. The eastern loop was installed to support the load growth in the northeastern area of the island, complete the encirclement of the island by the 230 kV system, and improve the transmission system reliability and capacity by increasing the available transmission lines to move electrical power from the

complex of generating plants in the south to major load centers in the north. The eastern loop runs from the large power production units in the southern plain at the Aguirre units in Salinas and the AES plant in Guayama to the eastern part of the island through Yabucoa and Río Blanco and terminates in Sabana Llana, southeast of the San Juan metropolitan area. Large sections of the new 230 kV eastern transmission line run along existing 115 kV rights of way. The project required the relocation of 16 miles of existing 115 kV lines between Río Blanco and Quebrada Negrito. The scope of the eastern loop project also included the expansion of the 230 kV facilities at the Sabana Llana and Yabucoa TCs.

The Authority is presently installing two new transmission line projects and recently completed construction of a new transmission center to expand the 230 kV transmission system. In addition to increasing the system capacity, the new transmission lines will provide additional redundancy for power flow from the major production units in the south, thereby improving operational flexibility for the system and support economic dispatch, as well as enhancing voltage stability at the major load centers and improving system reliability.

The Authority's priority project for expansion of the 230 kV transmission lines will connect the Costa Sur plant and the EcoEléctrica, L.P. cogeneration plant, both of which are on the south side of the island, with the key switchyard at the Cambalache combustion turbine station near Arecibo, which is on the north side of the island. The total length of the line will be 38 miles, however, more than half of its length consists of upgrading existing 115 kV line and structures to 230 kV, thereby shortening the construction schedule of the 230 kV line from the Costa Sur plant to the transmission center at Dos Bocas. Construction on this section of the new transmission line was completed late in fiscal year 2012. During the past fiscal year the new line entered service operating at 115 kV until the balance of the route to Cambalache is completed, when the entire line will be interconnected with the 230 kV system. The section of the new 230 kV line between Dos Bocas and Cambalache will utilize a new right of way. The Authority's current CIP shows spending on this project for completion in fiscal year 2014 will total $8.1 million; expenditures in fiscal year 2013 were $21.2 million. Completion of construction has been delayed pending resolution of certain disputed acquisitions of rights of way, however the Authority has scheduled the end of fiscal year 2014 to finish construction of the new 230 kV line.

The Authority plans to expand the 230 kV transmission system with a new line from the Aguirre generation complex to Aguas Buenas TC, via an extension in the Cayey TC. The transmission line project is scheduled for completion in fiscal year 2017 with expenditures of $889,000. The new line is scheduled to use a new right of way to provide an additional measure of redundancy and capacity for moving power from the critical generation source at Aguirre to the load centers in the north. This project will coordinate with a new 230 kV interconnection with the AES cogeneration plant to the east of the Aguirre complex.

The Authority has a long-term project for expansion of the 230 kV transmission system with a new 50 mile long line being constructed between the Costa Sur Steam Plant in Guayanilla and the Aguas Buenas TC, located south of the San Juan urban area load center. During the past fiscal year expenditures were $2.2 million and the project was approximately 66% complete. The estimated cost of the new line is $110 million, with completion planned in fiscal year 2020. Construction work is scheduled to resume in fiscal year 2018, with a budget of $5.0 million for that year.

Consistent with the installation of new transmission line projects the Authority expanded the capacity of the existing 230 kV switchyards at the Costa Sur plant and the Cambalache combustion turbine station. The initial expansion at the Costa Sur switchyard cost $2.8 million and was placed in service during fiscal year 2012. The $2.5 million expansion at Cambalache was completed in fiscal year 2013. In fiscal years 2015 and 2016 the Authority plans to add 230 kV switchgear at the Aguirre plant and the AES cogeneration facility, with a total cost of $3.1 million for the two projects.

115 kV System

The 115 kV system is comprised of 727 circuit miles of transmission lines that encircle and cross the interior of the island; the 155 kV system includes 35 circuit miles of underground lines. The 115 kV system was the first high voltage transmission system put into operation on the island to improve the efficiency and reliability of the bulk distribution of power. The 115 kV lines and substations serve all the major load centers on the island. Many of the 115 kV transmission line corridors were subsequently used as rights of way for the 230 kV system lines as that system grew.

In its plans for the long term expansion and improvements to the 115 kV system, the Authority has prioritized a number of new and rehabilitation capital improvement projects for 115 kV transmission centers

and other components of the system. Given the scope, complexity, and cost of these projects, their execution typically spans many years between initial work and placement into service.

Over the five fiscal years ending in fiscal year 2018, the Authority plans to complete two new 115 kV lines. The first new line is scheduled to start in fiscal year 2016 and will feed the planned 115/38 kV Bairoa TC, north of Caguas. The work is forecast for completion in fiscal year 2017 at a cost of $7.2 million. The next project will provide a second feed to the new Hato Tejas 115/38 kV TC; the line will run from the Palo Seco plant to the Hato Tejas TC in Bayamón. This project is scheduled to be worked on in fiscal years 2017 and 2018 with a total cost of $10.6 million.

During fiscal year 2013 the newly constructed 150 MVA 115/38 kV Hato Tejas transmission center located in the region of Bayamón was placed in service. Also during the past year the Authority continued work on two new 115/38 kV transmission centers. The first is a new 150 MVA 115/38 kV transmission center in Barraquintas. This new transmission center is located between existing transmission centers in Aguas Buenas and Juana Díaz and is scheduled for completion in fiscal year 2014. The Authority plans to continue work on a new 150 MVA 115/38 kV transmission center in Bairoa, part of Caguas; the project is scheduled to be completed in fiscal year 2016. During fiscal years 2014 and 2015 the Authority plans to install a new 115/38 kV transmission center at the existing Buen Pastor substation in Monacillos. Each of the new transmission centers is situated where it will help to reinforce the 38 kV system capacity and reliability by providing for additional operational contingencies. The budgets for these three projects total $13.4 million for the fiscal years 2014 through 2016. The CIP for fiscal years 2016 through 2018 includes $7.5 million for a new 115/38 kV transmission center in Venezuela, near Rio Piedras in San Juan; the project schedule has been extended to allow for resolution of local issues. Also in fiscal years 2016 through 2018 the Authority plans to install second transformers in three 115/38 kV transmission centers around the island for increased capacity.

The Authority continued work on the 115/38 kV switchyard utilizing gas insulated switchgear (GIS) at the San Juan plant during the past fiscal year. The new GIS will provide interconnection with the 38 kV system; interconnection to the 115 kV system will be via the existing aerial lines. The Authority plans a second phase of the GIS project to provide a permanent interconnect with the underground 115 kV system, meanwhile that connection can be accomplished on an interim basis if required. The final phase of the GIS project is scheduled for completion in fiscal year 2015.

During fiscal year 2014 the Authority plans to install and place into service two sectionalizers near the San Juan metropolitan area; the sectionalizers provide switchable isolation of portions of the 115 kV system, thereby improving operational flexibility to minimize the impact of a local problem. The Authority also plans to extend the busbar at the 115/38 kV Hato Rey TC located in San Juan. The scope of the work includes additional structures and breakers. The Authority plans five more extension projects at 115/38 kV transmission centers from fiscal year 2015 through 2018. The total budget for projects within this scope of work during the five fiscal years ending in 2018 is $12.9 million.

To protect the integrity of the transmission system in the San Juan urban area during and following extreme weather events, the Authority installed a 28-mile underground loop of 115 kV transmission cables that link the major components of its System in the metropolitan

area; the scope included four new 115/38 kV GIS substations, three of which are in operation. The general configuration of the loop is shown on the 115 kV underground system map, which is color coded to demarcate the construction phases. The system can be fed through existing transmission centers in the loop and by the Palo Seco units which are interconnected with the new transmission loop. The permanent interconnection of the San Juan units is planned for fiscal year 2015.

The principal function of the underground cable is to provide a robust measure of redundancy so that the Authority will be able to maintain continuity of service in San Juan's central business district, perhaps at partial load, in the event overhead lines are lost during a hurricane or other disaster. In addition, the cable will be available for back up service to the Authority's existing overhead transmission lines under normal circumstances. The scope of this project was prompted by the devastation caused by Hurricane Georges in fiscal year 1999. The Federal Emergency Management Agency (FEMA) reimbursed the Authority a total of $73 million of the project's cost of $195.8 million for the underground cable and ductbank scope of work.

The 115 kV underground work was installed in four major phases between fiscal years 2002 and 2008. All the underground 115 kV cable was fabricated using cross-linked polyethylene (XLPE) cable. While the XLPE cable was more expensive than cable insulated by oil or other chemical compounds it eliminated the possibility of environmental contamination if such compounds were to leak into the surrounding terrain.

The Authority incorporated provisions in the completed work for a future extension of the 115 kV underground system from the Isla Grande substation to the Covadonga substation in Old San Juan. This underground cable could provide increased load flow under normal and emergency conditions to the government buildings located in the Old San Juan area. The Covadonga 38 kV gas insulated switchgear distribution substation was constructed in a dedicated building that includes space for future 115kV equipment fed by an underground duct bank.

The 115 kV underground system includes four new substations incorporating gas insulated switchgear, providing for compact and enclosed substations. The first two new substations at Isla Grande and Martín Peña have been in service since fiscal year 2008. These substations were designed to support existing and anticipated load growth in their respective areas. The third and fourth substations are located at the Palo Seco and San Juan Steam Plants. The Palo Seco GIS has been in operation since fiscal year 2009.

38 kV System

More than half of the Authority's transmission system circuit miles operate at 38 kV, which is considered its "sub-transmission" level. While most of the sub-transmission system is near load centers, it is also the primary transmission system to some of the island's most inaccessible interior regions. At the end of fiscal year 2013 there were 1,375 circuit miles operating at 38 kV, including 63 miles of underground line and 55 miles of submarine service to the islands of Vieques and Culebra.

The 38 kV system feeds approximately two-thirds of the Authority's distribution substation capacity and almost all of the private substations on the island. Given that the 38 kV system is an essential component in the Authority's transmission network, for many years the Authority has been pursuing a system wide rehabilitation program to upgrade the reliability and capacity of the 38 kV system. In addition, the Authority continues to invest in new 38 kV system lines, switchyards and expansions. Both rehabilitation and new work are included in the Authority's CIP.

The scope of the rehabilitation work includes replacing old conductors with new, replacing aging wooden poles with steel poles and upgrading the system for forecasted local loads. In some areas, certain sections of the rehabilitated 38 kV lines have been installed along new rights of way to facilitate its installation as well as future maintenance.

In fiscal year 2013 the Authority expended $12.6 million on 24 projects of 38 kV line rehabilitation work. The largest project involved the major reworking of a line in the island's interior from Aguas Buenas to Barranquitas, which constituted approximately one half of the total 38 kV line rehabilitation expenditures. The project is budgeted for $5.2 million for fiscal year 2014, when it will be completed. Typically 38 kV line rehabilitation projects are located throughout the island and reflect the extent and age of the 38 kV system. During fiscal year 2014 the Authority has budgeted $15.1 million and plans to work on 25 line rehabilitation projects in the 38 kV system.

With regard to the 38 kV system transmission lines, the Authority's focus has been on rehabilitating existing lines. During fiscal year 2014 the Authority has budgeted $1.5 million for five projects to extend or increase the capacity of aerial 38 kV lines; the budget for fiscal years 2015 through 2018 for these expansions is $3.7 million, with funding for eight projects in

total. Expenditures in the past fiscal year were approximately one half million dollars for two projects.

The 38 kV system also includes more than 60 miles of underground cable in mostly urban areas. In response to civic and business leader requests, the Authority is expanding the scope of the underground cable in urban and industrial areas. During fiscal year 2013 the Authority expended $2.4 million completing an expansion underground 38 kV project in the Bairoa sector of Caguas. The Authority has deferred essentially all new 38 kV underground lines during fiscal years 2014 and 2015, but is planning to resume selected projects in 2016. The total budget for fiscal years 2016 – 2018 is $17.9 million for four projects.

Transmission Plant Capital Improvements

The transmission plant funding forecasts in the Authority's current CIP address a wide range of improvements covering the entire transmission system. Transmission capital expenditures in fiscal year 2013 amounted to $69.7 million. The Authority is planning to spend $66.3 million on capital improvements to its transmission system in fiscal year 2014: $26.7 million for expansion projects and $39.7 million for rehabilitation projects. The Authority plans to spend $329.5 million on its transmission system over the next five fiscal years. These expenditures are discussed in the *Capital Improvement Program* section and are itemized in *Appendix X, Details of Capital Improvement Program* and summarized in *Appendix VI, Capital Expenditures.*

DISTRIBUTION

The Distribution System is the final link between the Authority's production plants and Transmission System and its clients, with the exception of the small number of commercial and industrial clients who purchase power at the transmission level. The Distribution System includes Authority owned substations that reduce the power from transmission voltage to the level at which it is locally distributed; the three voltage levels serving most clients are 4.16 kV, 8.32 kV and 13.2 kV, with a small portion distributed at 7.2 kV. At the end of fiscal year 2013 there were approximately 31,550 circuit miles in the distribution system. The circuit miles operating at 13.2 kV and 8.32 kV are each approximately 24% of the total distribution circuit miles, with 4.16 kV lines accounting for most of the balance.

While most of the Authority's primary distribution systems are overhead, almost 6% of the Authority's distribution circuit miles are underground. The Authority's aerial distribution systems are conventionally located along road rights of way, although some are located along rear lot lines or installed along the Authority's rights of way. To improve operational reliability the Authority has a program to relocate high value lines from rear lot lines to more accessible rights of way. Service ties from the distribution lines and meters complete the connection to clients' premises.

Selected 13.2 kV Projects

The Authority has a long-standing program in place to upgrade its primary distribution level to 13.2 kV. The higher voltage is a cost effective method that enables the existing conductors to carry more load, while updating older distribution equipment such as transformers, switches, capacitors and reclosers. In addition, operating at 13.2 kV reduces line losses and allows for longer circuits runs, thereby providing more flexibility in making system interconnections. During fiscal year 2013 the Authority expended $3.5 million on the construction and extension of new overhead 13.2 kV lines in nine projects. During the past fiscal year the Authority expended $6.6 million for new and extending 13.2 kV feeders at 24 substations. Including the special project in Ponce discussed below, expenditures for underground 13.2 kV lines during fiscal year 2013 were $15.5 million.

The Authority makes on-going investments in new distribution substations to support new or increasing load, such as in areas with increasing residential construction, to improve system performance and to replace aging equipment. The Authority has standardized on two sizes of permanent substations based on the transmission system supply voltage. This standardization expedites the engineering, procurement, and construction cycle, increases flexibility in potentially utilizing equipment as spares, and provides a cost effective installed capacity margin for load growth. In situations where the Authority needs additional substation capacity on an interim basis or with short lead times, the Authority installs temporary substations that are standardized unitized metal clad equipment, which can be relocated as required.

During fiscal year 2013 the Authority completed the construction of new 13.2 kV substations at Río Bayamón II and Hato Tejas, both in the Bayamón region, and completed work to increase the capacity of substations at Cayey in Caguas and at Palmer TC in Carolina. In the past fiscal year work was completed to install an additional transformer at the Grana II substation in San Juan. All are scheduled to enter service early in fiscal year 2014. During fiscal years 2014 and 2015 the Authority plans to construct

five new 13.2 kV substations. These substations will be at Sea Land (Caparra) in Guaynabo, at Charco Hondo in Arecibo, at Añasco in the west coastal area of the island, at Morovis in the central region west of San Juan, and at Las Piedras in the eastern central region. The Authority has allocated a total budget of $27.4 million for 12 new substation projects during the five years through fiscal year 2018; $5.8 million is budgeted for increasing the capacity of existing substations during the same five years.

In compliance with a settlement with the municipality of Ponce, the Authority agreed to improve the electric distribution system in the historic district of Ponce. The project involves upgrading the existing overhead 4.16 kV system to a 13.2 kV underground distribution system. The Authority has taken the lead in the underground work in the historic district which requires coordination with the telephone company and the water and sewer utility who are also concurrently relocating buried utilities in the same district. The scope of the entire project is being executed in four sequential phases to minimize disruptions to the neighborhoods and local traffic. The first two phases of the work have been completed and placed in service. The third phase of work began in fiscal year 2011 and was essentially completed by the end of the past fiscal year; expenditures during the past fiscal year were $8.9 million. Work on the final phase is targeted to begin late in fiscal year 2014 or early the next fiscal year, with a duration of four years. The CIP budget for this project through 2018 is $12.9 million.

Other Distribution Work

Consistent with the wide use of lower voltage distribution lines and equipment, during fiscal year 2013 the Authority expended $34.2 million on improvements to the distribution system and overhead distribution lines at 4.16 kV – 8.32 kV. Expenditures on improvements to underground distribution lines operating at 4.16 kV – 8.32 kV totaled $10.3 million in fiscal year 2013; these improvements typically are in urban areas.

To improve client service and reduce operating costs, the Authority is expanding the installation of various distribution automation equipment systems to respond to line faults. The fault detection, isolation and restoration (FDIR) system selected for priority distribution lines will automatically isolate the fault and transfer loads to an alternative feeder to minimize the duration and number of clients impacted by the fault; the system provides real time information to the Authority's operation center on its actions and status.

The FDIR system has the capability to isolate faults and restore service in response to multiple contingencies, such as might happen during severely inclement weather. The Authority has also installed reclosers for fault detection and isolation without automatic load transfer, however these systems include remote communication to facilitate manual response. The Authority's CIP budget for the five fiscal years through 2018 is $4.0 million for the installation of distribution automation equipment.

The Authority has an on-going program to comply with recent EPA's requirements on Spill Prevention Control and Countermeasures (SPCC) Plans pertaining to their electrical distribution system equipment containing oil. The Authority's SPCC Plan includes spill response material and notification signage at all substations. This scope of the plan was fully implemented during fiscal year 2012. In addition, the SPCC Plan has identified 58 substations in which spill containment dikes will be installed under transformers and oil containing circuit breakers. By the end of fiscal year 2013 the Authority had installed the majority of these modifications at 42 substations. Authority plans to complete all the required SPCC works modifications at the affected substations in fiscal year 2015.

The Authority owns 22 portable distribution substations that enable them to perform substation maintenance with minimal or no interruption of service, to speed recovery after a substation failure, and for enhanced operation during line clearance constraints. The portable equipment ranges in size from 10 MVA to 44 MVA at 38 kV and 115 kV, and includes two capacitor banks at 38 kV 18 MVAR.

Distribution Plant Capital Improvements

The Authority's capital expenditures on the distribution system were $127.9 million in fiscal year 2013. The scope of these expenditures included $16.0 million in the past year for the remote read meters program discussed below. The Authority is planning to spend $99.9 million on capital improvements for its distribution system in fiscal year 2014: $18.8 million for expansion projects and $81.1 million for rehabilitation projects and other distribution expenses, such as remote read meters, line transformers, breakers, sectionalizers, and reclosers. The remote read client meters discussed below have been a long term capital commitment by the Authority and they account for 12% of the Distribution CIP budget for fiscal year 2014. The Authority plans to spend $465.1 million on its distribution system capital improvements over

the next five fiscal years; this is 30% of the total planned capital expenditures over that period.

MAINTENANCE

The Authority generally maintains its transmission and distribution equipment using a time-based system. In some cases the maintenance intervals have been modified to meet the challenging tropical environment or relevant operating experience. As an example of routine periodic inspections, the Authority performs infrared inspections of all substations and switchyards twice a year. The infrared inspections are used to identify "hotspots" which are faulty connections that are overheating and are likely candidates for failure. In addition to performing electrical and mechanical testing, the equipment is painted on a periodic basis to help prevent corrosion.

The Authority's inspection and maintenance program for high voltage electrical equipment is based on the criticality of the equipment's service, with the scope and frequency of the inspections and maintenance guided by the manufacturer's standard recommendations. Main power, transmission and substation transformers are inspected on a four year cycle. The Authority takes oil samples annually from all high voltage transformers in an effort to identify internal deterioration before it leads to failure. The Authority's oil analysis program relies on a recognized industry consultant's recommendations, coupled with its own operating and maintenance experience, to perform more frequent monitoring or eventually repair. As many major transformers approach their design service life this program has become increasingly important in maintaining the system operating reliability.

The inspection and testing frequency for other high voltage equipment in the maintenance program include: gas circuit breakers—six years; oil circuit and vacuum circuit breakers—four years; and protective relays—no more than three years for calibration and testing. Relays protecting major equipment, such as transmission transformers, are tested more frequently based on when the equipment is out of service.

In response to sporadic theft of aluminum structural bracing members for their scrap metal value from transmission towers in past years, the Authority has increased inspections of transmission towers using both the helicopter patrols and inspections from the ground. Any deficiencies identified in these inspections are repaired on a priority basis.

In fiscal year 2013 the total operation and maintenance expenses for the Transmission and Distribution systems was $277.1 million. While this level exceeded the budget, it equaled the average expenditures for the most recent three fiscal years 2011 through 2013. The budget for total operations and maintenance of the Transmission and Distribution systems for fiscal year 2014 is $271.0 million, which is 2.2% less than the previous year's actual expenses; the differences between the budget and the previous years' actual expenses are principally reductions in operations costs. The maintenance budget for the five fiscal years 2014 through 2018 for the Transmission and Distribution systems through 2018 is forecasted to be 4.9% above the actual expenditures of fiscal year 2013. The Authority's total Transmission and Distribution operation and maintenance budgets for the four fiscal years 2015 through 2018 are forecasted to decrease 7.4% in fiscal year 2015, increase 1.1% and 0.3% in 2016 and 2017 respectively and remain unchanged in 2018.

Transmission system maintenance expenses, shown in *Appendix III, Detail of Operating and Maintenance Expenses,* totaled $30.0 million in fiscal year 2013; the expenditures were 2.7% less than budget. For fiscal year 2014 the Authority has reduced the annual transmission maintenance budget to $17.4 million, with the five-year average through fiscal year 2018 being $17.1 million. In these same time frames the budget for transmission system operations increased from the actual expenses of $19.3 million to a budget of $26.1 million; the five-year average through fiscal year 2018 is $25.0 million for transmission operations. Activities included in the maintenance budget include funding for tower maintenance, tree trimming, insulator replacement, helicopter patrolling of transmission lines, and right of way management. The costs associated with the transmission system portion of substation maintenance are also included in these budgeted expenditures.

Distribution system maintenance expenses, also shown in *Appendix III, Detail of Operating and Maintenance Expenses,* totaled $74.7 million in fiscal year 2013; the expenditures were 18.6% over budget. For fiscal year 2014 the Authority has increased the annual distribution maintenance budget to $94.9 million, with the five-year average through fiscal year 2018 being $92.8 million. In these same time frames the budget for distribution system operations decreased from the actual expenses of $153.0 million to a budget of $132.6 million; the five-year average through fiscal year 2018 is $126.6 million for distribution operations. The distribution maintenance expenditures include distribution system related

expenditures similar to those described under transmission system maintenance expenses.

TRANSMISSION AND DISTRIBUTION SYSTEMS RELIABILITY

The principal guideline in the operation of a utility electric system is to continuously balance the real time demand for electricity (the load) and the simultaneous production of power while maintaining regulation of the system's voltage and frequency. The electric system is designed to meet this requirement across a wide range of operating conditions, which include loss of an operating transmission line or other key system component. Analyses of these design conditions establish the required redundancies in the system and operating criteria. Consistent with industry practice, the Authority has designed the entire transmission system to maintain continuous operation with at least one contingency event (loss of an operating component) and two contingencies for critical lines that move power from the major production plants.

Reliability Indices

Reliability standards have been in place within the North American electric utility industry for many decades. Following recent wide spread power losses in America, such as the Northeast blackout in August 2003, the electric power industry and its regulators have reaffirmed the importance of reliable service to support the requirements of the economy. This was reinforced in the Energy Policy Act of 2005, which called for mandatory reliability standards for the interstate bulk power systems. The Authority's experience is consistent with the industry in that while the notorious blackouts are caused by the transmission systems, most interruptions to client service are caused by problems in the local distribution system.

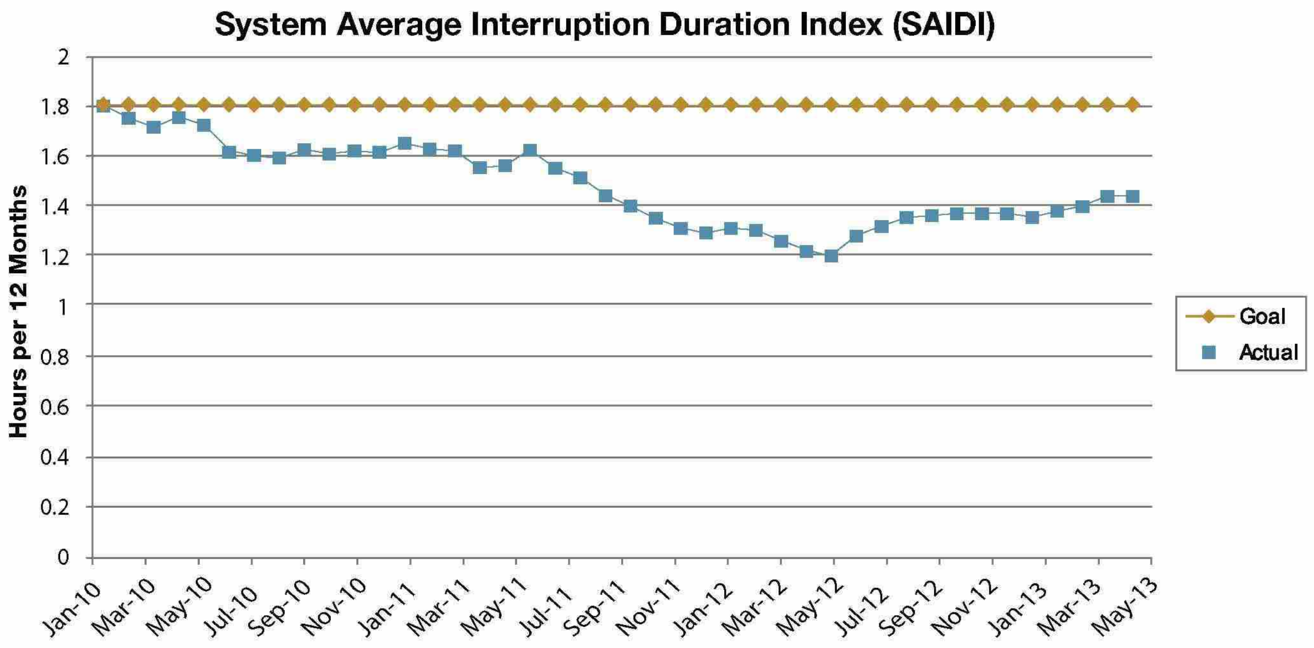
Two industry criteria generally accepted for measuring an electric system's reliability of service to its clients are the following:

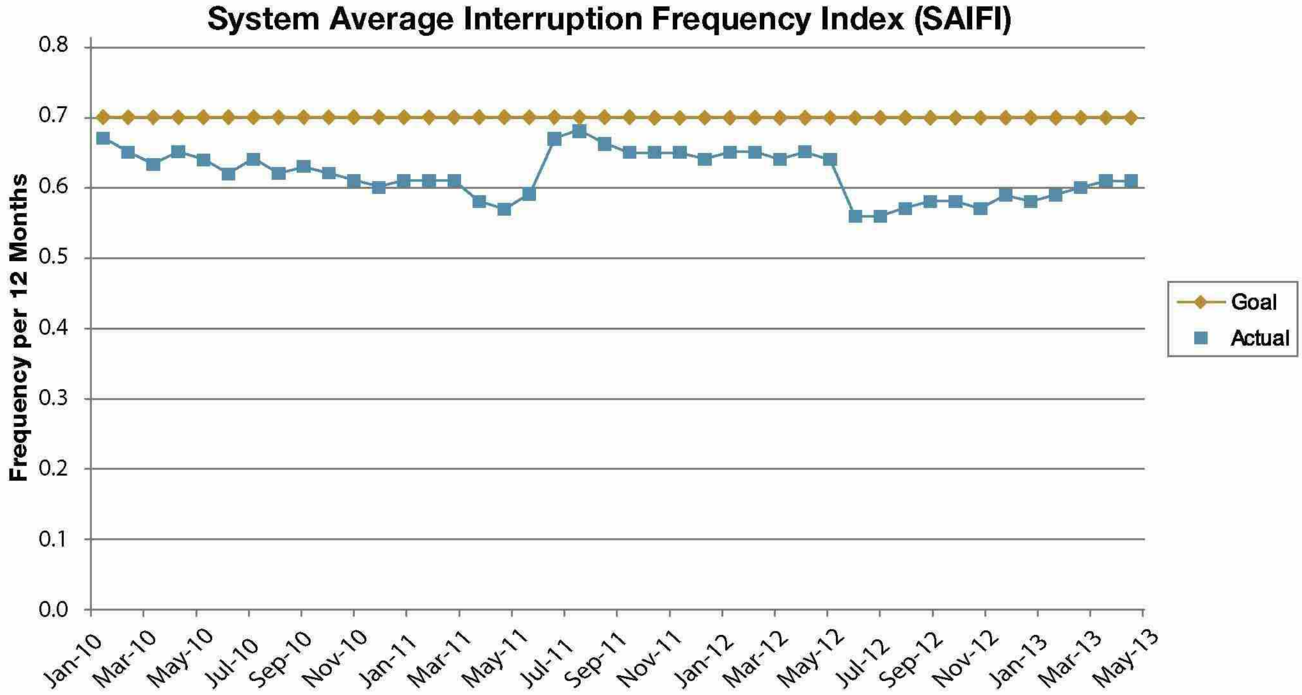
System Average Interruption Duration Index (SAIDI)- The average duration of sustained service interruptions per client occurring during the preceding twelve-month period. It is the average time a typical client was without power over a rolling twelve-month period. The average is determined by dividing the sum of the durations of all sustained client interruptions by the total number of clients served. The Authority reports its SAIDI duration statistics in hours.

System Average Interruption Frequency Index (SAIFI)- The average frequency of sustained interruptions per client occurring during the preceding twelve-month period. It is calculated by dividing the total number of sustained client interruptions by the total number of clients served.

SAIDI and SAIFI indices take into account only sustained outages; they do not reflect momentary interruptions or voltage irregularities, which can affect sensitive electronic equipment. For both SAIDI and SAIFI, lower index values indicate better client service, i.e. shorter and fewer service interruptions.

Throughout the electric power industry the general procedure for calculating reliability indices has been implemented by most utilities with their own specific adjustments to reflect their service conditions. The





Authority's SAIDI and SAIFI data include only outages longer than fifteen (15) minutes and exclude major events, such as the effects of tropical storms/hurricanes and disruptions from multiple contingencies.

The charts provide perspective on the short term trend of the Authority's SAIDI and SAIFI data over the period beginning in January 2010, when the Authority established the goals still in place and ending on June 30, 2013. During this timeframe the average duration and frequency of service interruptions have usually stayed in a relatively narrow band, but have trended on a gradual downward slope. In comparison to the reliability indices of five years ago, however, the recent SAIDI and SAIFI data are considerably below the levels in fiscal year 2008. To achieve these significant reductions in service interruptions the Authority prioritized improving the reliability of the distribution system. A critical component in the Authority's program was to re-establish emphasis on tree trimming and vegetation control programs that specifically address a major cause of service interruptions. The scope of the Authority's on-going program includes both transmission and distribution lines, as well as public education of appropriate plantings located near overhead power lines. To reinforce its objectives over the last ten years the Authority progressively dropped the performance index goals of fewer and shorter interruptions (lower SAIDI / SAIFI). The most recent reduction in January 2010 lowered the target SAIDI by 10% and SAIFI by 30% to reflect the Authority's objectives in continuing to improve client service.

As the Authority's SAIDI and SAIFI goals have dropped and become more challenging to achieve and maintain, the margin between the goals and actual performance has shrunk. This past fiscal year continued a general trend that began in fiscal year 2009 indicating that additional significant reductions in the average duration and frequency of interruptions may be difficult to achieve in the near term.

The average total duration of a client's sustained interruptions during the past fiscal year, as shown above in the Authority's 12-month rolling average of SAIDI, was consistently below the Authority's current goals although it trended somewhat higher as the year progressed.

During fiscal year 2013 the twelve-month rolling average of the number of sustained outages per client trended in a relatively narrow band that was consistently below the Authority's SAIFI goals for the year. As mentioned above, the observed performance was basically consistent with the interruption frequency for more than the last three fiscal years.

As the Authority reduces the outages caused by trees and vegetation, one key to further improving the Authority's reliability performance will be the identification of the cause of service interruptions. The potential integration of the proposed, improved automated systems and Remote Meter Reading may allow more detailed analysis of reliability data. In addition,

it would be possible to acquire data on an individual client's actual experience rather than relying on composite averages.

TECHNOLOGICAL SYSTEMS OPERATIONS

The Authority employs numerous automated control systems to ensure safe and reliable operation of its System. These systems coordinate with or are integrated into larger systems that support the Authority's routine technical and commercial operations. This section addresses selected automated systems employed by the Authority for control and operation of the generation, transmission and distribution systems.

ENERGY MANAGEMENT SYSTEM

Consistent with good operating practice in the industry the Authority uses a sophisticated control system to regulate operation of its production sources to always match in real time the System's consumption of electric power while maintaining the proper voltage and frequency.

In fiscal year 2010 the Authority contracted with the energy management system (EMS) supplier to modernize the EMS that had been in operation for more than 11 years by that time. The vendor of the latest generation EMS was chosen to facilitate the design of the new EMS to meet the Authority's new requirements, provide continuity of operator interface and minimize potential issues during the transition to the new system. Although the EMS in operation since 1999 had continued to function properly with the existing System, the EMS hardware and software were aging and the Authority's performance requirements had evolved to include operation of the System with intermittent renewable energy generation sources and wheeling mandated by Commonwealth legislation.

Following completion of several factory acceptance tests, in fiscal year 2012 the new system and training modules were installed in the Authority's control centers. Since the new EMS was developed by the same vendor who supplied the present system, similarities in their architecture facilitated the training; the operator training simulator also includes distributed generation and wheeling. During the first half of the past fiscal year the Authority operated the new system in parallel with the existing for many months to demonstrate reliable operation of the new before retiring the existing from service.

The new EMS also updates the Authority's cybersecurity system for compliance with North America Electric Reliability Council's (NERC), critical infrastructure protection (CIP) standards.. Approximately one half of the funding for the $7.5 million replacement EMS was obtained through the U.S. Department of Energy's "Recovery Act Smart Grid Investment Grant Program". The new EMS can interface with the distribution management system, which is an important communications link for "Smart Grid" technologies. In addition, the vendor of the new EMS system offers pre-engineered features if the Authority wishes to expand the system's scope.

Concurrent with the development of the new EMS, the Authority has been upgrading the supervisory control and data acquisition (SCADA) system functionality. The SCADA system is the secure communications network linking the central EMS with all the generation sources and substations.

The scope of work for the new EMS includes new hardware and software to replace the existing control system in both the primary energy control center in Monacillos and the back-up control center in Ponce. The upgraded EMS will enhance the Authority's ability to respond to critical situations if the primary control in Monacillos is limited or compromised, based on continuous real-time data synchronization between the two control centers and enhanced system error detection and failure determination. The EMS features include extension of the Authority's load forecasting and load flow analysis. The automatic generation control (AGC) is based on revised economic and security criteria. Among the network applications are power scheduling opportunities, improved software for the analysis of disturbances, phase angle and frequency monitoring and for the detection and analysis of inter-area oscillation. The new EMS will more accurately identify fault locations thereby facilitating faster service restoration and interface with the distribution outage management system.

ASSET MANAGEMENT SYSTEMS

During fiscal year 2013 the Authority implemented an upgraded program of work and asset management systems for its users responsible for generation and the high voltage electrical system, while evaluating programs for transmission and distribution activities.

Production Plant Asset Management Systems

In fiscal year 2010 the Authority began a program to upgrade its enterprise asset management systems (AMS) that support its generation and high voltage assets to more effectively monitor and manage these critical assets and associated inventory. The objective

has been to improve their reliability, safety and availability, while reducing costs. The previous system had been in place for more than a decade and had been superseded by newer technology. The supplier of the new AMS suite of programs is well established in this field and has direct relevant experience with electric utilities; the supplier is also the successor to the previous AMS vendor. The new AMS is designed to improve coordination with the numerous directorates that are involved in the management of the production and high voltage electrical assets. It will facilitate the integration of data into the different programs used within the human resource, financial, engineering, procurement, and management disciplines.

Following acceptance testing, establishing the databases for the new AMS based on the earlier AMS program as well as with new data, and widespread training, the Authority fully implemented the new AMS during the past fiscal year.

The new AMS scope includes modules that address work and asset management through maintenance optimization, life extension, work planning, predictive failure, materials and planning, monitoring of critical equipment on a real time basis, and analysis of historical performance data to improve repair or replace decisions. The suite of programs are designed to support effective management of supply chain responsibilities, maintenance of critical spares, purchasing, expediting, material receipt, management of accounts payable, and quality control. In addition the AMS includes safety and compliance management components that identify requisite safety training requirements for the work being performed, possible chemical exposures, permit requirements, document control procedures, and environmental compliance.

Transmission & Distribution Asset Management Systems

Presently the Transmission & Distribution operations of the Authority use a multi-faceted work and asset management system that is more than ten years old. The Authority's transmission and distribution asset management system integrates a work management system, a geographic information system and an outage management system into an Integrated Resource Management System that is known by its Spanish acronym of AIRe (Administracion Integrada de Recursos).

The AIRe system is structured to maintain its databases as well as interface with existing computerized systems in other Authority areas such as Finance, Human Resources, and Procurement. The objectives of the AIRe are improved client service; reduced O&M expenses; improved emergency response; better planning; improved and consistent engineering/design and estimating practices; archived maintenance records; and, real-time system status reporting.

Since the AIRe system was implemented more than ten years ago, the applicable vendors, hardware and software technologies have evolved. During fiscal year 2011 the Authority re-evaluated various options to replace the existing AIRe system that was originally supplied by a vendor who was subsequently acquired by a larger vendor; the new vendor agreed to support the old system for only a limited time. The Authority established continuity of the user interface with which the transmission and distribution users were accustomed as an essential feature in selecting its replacement state of the art asset management system. The evaluation process of alternative AMS systems continued through the past fiscal year. The Authority plans to make its selection in fiscal year 2014, at which time the schedule for implementation of the new system will be established. The Authority plans that the new asset management system for transmission and distribution work will include interfaces with the production AMS, as well as interface with the outage management system and geographical information system with web based technology.

The work management system (WMS) component of the AIRe system has been in service in all of the Authority's districts since 2001. The WMS tracks the progress of all construction and maintenance work from start to completion. The functions of the system include estimating, engineering, scheduling, required approvals, the generation of bills of material of approved equipment in accordance with Authority standard designs, and the accumulation of labor and material costs for each project.

The geographical information system (GIS) component of the AIRe system is a comprehensive geospatial model of the entire transmission and distribution systems including an inventory of all components. The GIS database is designed to interface with the WMS and the outage management system (OMS), as well as providing an engineering tool for modifications, new work, and circuit analyses. Completing the GIS was a major task since the global positioning system (GPS) coordinates of every pole on the island had to be plotted and all the associated equipment physically inventoried. Subsequently the Authority expanded the scope of the GIS to include validating

the location of client meters to improve the precision of the outage management system discussed below. The GPS coordinate data are utilized with a one-meter resolution satellite map database of the entire Commonwealth that was developed by a Puerto Rican interagency governmental group.

The outage management system (OMS) has been in island-wide operation since the end of fiscal year 2008. The OMS is designed to improve the Authority's recovery efforts following a hurricane or tropical storm by generating: a damage assessment report based on data received from various system transponders and the Customer Information System; a complete inventory of equipment needing replacement; maps of all areas affected by the outage(s); and, an up-to-the-minute report of the System's status. When the restoration work is underway, the AIRe system monitors and records the labor and material costs.

In conjunction with the OMS system the Authority expanded the use of an automatic vehicle location (AVL) system to 750 vehicles. The AVL system is capable of providing the real-time location of any Authority vehicle fitted with the GPS receiver and communication link to the Authority's local dispatch center. Vehicle location information has been useful in reducing travel time to respond to problems and routing assistance to work crews if required. The AVL also enhances the safety of the crews by providing their location whenever it may be needed, such as during wide area power restoration work. Since the experience with the AVL system has been favorable, the Authority plans to eventually install it in all emergency vehicles.

Since the Authority completed the installation of the work management system in each district and implemented the interface with the Customer Information System, Customer Services operators can access the WMS to provide timely information to clients. During emergencies, all the commercial offices located across the island are integrated into the work management system, allowing trouble orders to be immediately generated electronically. The implementation of these automated systems has allowed the Authority to consolidate many of its Customer Service centers.

REMOTE METER READING

In fiscal year 2000 the Authority began the island-wide installation of an automated meter reading (AMR) system. The primary goal that the new meters support is the ability of the Authority to remotely read the parameters measured by the meter of all clients. Industrial and commercial clients served at transmission voltage are a small portion of the total client base; the high voltage meters for these clients are not included in this discussion, however these meters do provide remote reading capability. During the course of the remote meter reading program the meters have gone through technological evolutions, which are discussed below. Capital expenditures for the AMR system in fiscal year 2013 were $16.0 million, bringing the total to approximately $225 million; $43.4 million is budgeted for fiscal years 2014 through 2018. The continuing program consists of actively replacing old and defective meters and the selective installation of new design digital meters. By the end of fiscal year 2013 automated meters had been installed in effectively all of the Authority's clients. The system being installed utilizes a proprietary technology that communicates between meters and remote controllers by superimposing a frequency modulated signal on the Authority's existing distribution lines between the client meter and the Authority's substation. Because it uses the electric power wires, this technology's performance is not impaired by the island's varied terrain.

Communication between the AMR system central processor and the individual meters is through dedicated transformers and communication equipment installed in the substation serving the associated client's meter. The processed signals from the AMR substation equipment are routed to the central processor via the Authority's existing fiberoptic, microwave systems or secure internet. The AMR equipment is installed at all the Authority's active substations and all new substations include the AMR equipment with the original construction.

The Authority's early experience with the AMR meters exposed weaknesses in the meter's resistance to tampering. During the first ten years of deployment the meter technology evolved from electro-mechanical meters with communication modules to rugged digital meters, fitted with the same communication module. Over the years the Authority has worked with meter vendors to develop increasingly robust units to resist tampering. It has also enhanced sealing of the plastic case of meters that were already in inventory but had not been deployed. The Authority now buys meters with the most robust anti-tampering specifications commercially available; these meters also include internal memory good for storing many months of data, which might be used if tampering or theft were suspected, or for data recovery if the AMR communications were disrupted. Beginning in fiscal year 2011 the Authority has been

installing meters with an integral disconnect/connect feature. These meters have greatly reduced the time required for customer service disconnections and reconnects for short term clients or in problematic locations. In most instances these meters enable a client to re-establish disconnected service after making a secure payment of an overdue invoice by phone or internet within minutes of that payment. By the end of fiscal year 2013 there were approximately 170,000 meters with this technology installed.

During fiscal year 2013 the Authority continued its aggressive theft detection and prevention program. Amongst other detection techniques, the program utilizes the comparison of local/temporary meters on the distribution lines versus the aggregate of the individual served meters, a comparison of a client's present electricity usage versus historical data, unannounced meter inspections, and a toll free hot line for anonymous reporting of suspect electricity theft. Based on recent experience, the Authority anticipates the theft recovery program will generate considerable additional revenues and help deter further theft. As discussed in the *Legal Affairs* section the Authority has established legally binding administrative processes to recover contested billings for theft from culpable clients.

As the technology for remote meter reading has evolved the Authority has identified certain applications which may benefit from enhanced access to the client meter data. The meter data management system may be used for enhanced data input to the OMS discussed above. The Authority is also evaluating using the AMR system to provide data to support the upgraded EMS, discussed above, which will be the principal system for controlling the generation and transmission of power on the island. The electrical power consumption data could also be used to support analyses of operational performance and time based pricing structures that may be evaluated in the future.

The Authority plans to upgrade the AMR communication equipment at its large substations to improve data transfer speed. In addition, the Authority plans to install internet communication with the AMR communication gear at many of its substations to improve reliability and provide operational flexibility.

Although they are not among the AMR system features now being installed, the AMR has the capacity to incorporate at a later date the ability for the Authority to simultaneously monitor and control the performance of key components of its distribution system. This two-way communications is a critical attribute of the "Smart Grid". By controlling such devices from a central location, the Authority would be able to enhance its capability to control load flow, manage restoration of service from an outage, and improve the operational power factor. If added, this type of control could reduce operating costs, improve client satisfaction, and facilitate Demand-Side Management & Energy Conservation (DSM & EC) programs by allowing the utility to control its clients' energy use; refer to the *Demand and Energy Forecast* section.

GENERAL FACILITIES

The budget for capital improvements for the General Plant encompasses General Land and Buildings and Equipment. During fiscal year 2013 the budget for General Plant capital improvements amounted to $29.3 million. The actual expenditures during fiscal year 2013 were $22.3 million; the savings from budget resulted principally from reductions in expenditures for improvements to buildings and grounds for administration services and improvements to warehouses. As shown on *Appendix X Details of Capital Improvement Program,* the expenditures for General Plant for fiscal years 2014 through 2018 are forecasted to be $33.8 million, $31.3 million, $29.9 million, $32.8 million, and $32.2 million, respectively.

Maintenance expenses for the General Plant in fiscal year 2013 were $6.9 million. While this level was below the original budget of $9.3 million, it was within 6% of the previous three-year average expenses. The Authority's maintenance budget for General Plant in fiscal year 2014 is $8.8 million.

The extensions and improvements planned for fiscal year 2014 include $7.2 million for General Land and Buildings. The largest budget item in this group is for the acquisition of transmission and distribution rights of way and land for planned expansions. Other expenditures within this category are for improvements to the Authority's warehouses, workshops, offices, buildings, and grounds. The Capital Improvement Program for fiscal year 2014 includes funds to complete the structural rehabilitation of the plaza at the Authority's headquarters in Santurce, San Juan, as well as other improvements to various administrative services buildings.

The total expenditures for Equipment in fiscal year 2013 were $17.8 million; office and computer equipment accounted for $9.0 million, overhaul of the large helicopter used for installing and rehabilitating transmission lines cost $1.9 million and $3.8 million was expended on replacement vehicles. For fiscal year

2014 the total Equipment budget is $26.6 million; this is comprised of four budget subgroups, as follows: The Office and Computer Equipment budget for fiscal year 2014 is $5.6 million. The largest project is $2.8 million for improvements to the information services systems as part of a long term upgrade that has a budget of $18.4 million for the five fiscal year 2014 – 2018. The Transportation Equipment budget is for repairs or improvements to the Authority's aircraft and for purchase and replacement of the Authority's vehicles; the budget for fiscal year 2014 is $8.3 million. The Communication Equipment budget is $4.2 million for fiscal year 2014; this budget is directed to improving and expanding the communication network used by the Authority for operation of the System. The projects include improvements to the fiber optic network and upgrading the microwave system between essential facilities. The last Equipment subgroup is Other Equipment, which has a budget of $8.5 million for fiscal year 2014. The scope of this subgroup spans a wide range of equipment including miscellaneous tools used for the installation of transmission and distribution lines, environmental monitoring equipment, specialized power quality monitoring equipment, vehicle repairs tools, and small construction tools.

CONDITION OF THE SYSTEM'S PROPERTIES

The Consulting Engineers visited and noted the condition of each of the Authority's steam-electric generating facilities three or more times during fiscal year 2013 and also visited the other production facilities at least once during the fiscal year. In addition, we also visited and noted the condition of approximately one-third of the Authority's three hundred and eighty transmission centers and distribution substations. In the course of these visits we observed other property in the production, transmission, distribution, and general plant functional groups.

In conjunction with our field activities, we have reviewed various maintenance reports of the Authority, specific maintenance activities, and the planned actions for the next fiscal year. We have also reviewed reports submitted by manufacturers' representatives.

In the opinion of the Consulting Engineers, the properties of the System are in good repair and sound operating condition.

CURRENT FORECAST

During the second half of every fiscal year the Authority prepares a forecast entitled Presupuesto de Ingresos (Revenue Budget) that projects energy sales by service sector, revenues, and number of clients, as well as projected generation, annual peak demand and fuel costs. This annual report references the Authority's Revenue Budget as the "Current Forecast". The Current Forecast contains detailed short to intermediate-term projections of energy sales revenues, number of clients, and fuel prices based on Energy Information Agency (EIA) projections and other sources; the forecast also includes projections of long-term generation and long-term peak demand. The remainder of this section will describe the results of these forecasts and the methodologies used in its preparation.

The preparation of the Current Forecast is timed so that its projections may be used to develop short-term (1-2 years), intermediate-term (3-5 years) and long-term projections (6 years and beyond) of various financial and operational parameters. The initial year of the short-term financial projection is used for the Authority's Annual Budget of Current Expenses (Annual Budget) for the ensuing fiscal year. The short to intermediate-term energy projections are utilized to establish the Authority's needs for capital requirements and the projected income statements, which are used in turn to project its ability to meet the necessary requirements of its Trust Agreement covenants regarding net revenues to projected debt service.

The long-term peak demand and generation projection through fiscal year 2040 are generally used for trends of generating capacity that may be needed in the future. (See Capacity and Energy Resource Planning) The Authority developed a Current Forecast in April 2013 as the basis for the fiscal year 2014 budget, financial projections through fiscal year 2018 and long-term generation and peak-demand projections through 2040.

To establish energy sales data for fiscal year 2013, which is the base year in the Current Forecast, the Authority's Planning Directorate used actual energy sales from July 2012 through February 2013 and preliminary generation data for March 2013. These energy sales do not include the adjustments applied principally to the industrial class sales to avoid distorting the base year of the forecast; the adjustments are discussed in the *Energy Sales Forecast* section. The estimate for energy sales for the remaining months of fiscal year 2013 were extrapolated from

generation data for the comparable months in the five-year period ending in fiscal year 2012, while sales by service sector were estimated to follow the average distribution of the 12 months through March 2013. The projections for energy sales and related data for the period of fiscal year 2013 and after were based on econometric modeling of energy sales by service sector. Macroeconomic indicators provided by economic consultants are key dependent variables for these models. The Authority also has extrapolations of energy sales by service sector based on monthly data since fiscal year 1993 and annual data since 1983. Generation requirements are derived from sales projections, adjusted to reflect system operating losses. The forecast methodology reduces data to a daily basis to allow adjustment for leap years.

The short-term and intermediate-term forecasts project sales, revenues, number of clients, generation, and maximum demand on a monthly basis for the remainder of fiscal year 2013 and for all of fiscal year 2014 and on an annual basis thereafter through fiscal year 2018. Projections of fuel costs are also provided through fiscal year 2018. The long-range forecast projects annual generation (in GWh) and peak demand (in MW) through fiscal year 2040.

The projected revenues in the Current Forecast are derived from the forecast energy sales by classification using existing base rates and the appropriate projected adjustment charges for the cost of fuel and purchased power. The Current Forecast also includes projections for the reductions due to subsidies and credits applied to the fuel and purchased power revenues and the hotel subsidy, but these reductions are not incorporated in the total revenue forecasts. The Authority's forecasted revenues and payment obligations are discussed in the *Financial* section.

ECONOMY OF PUERTO RICO

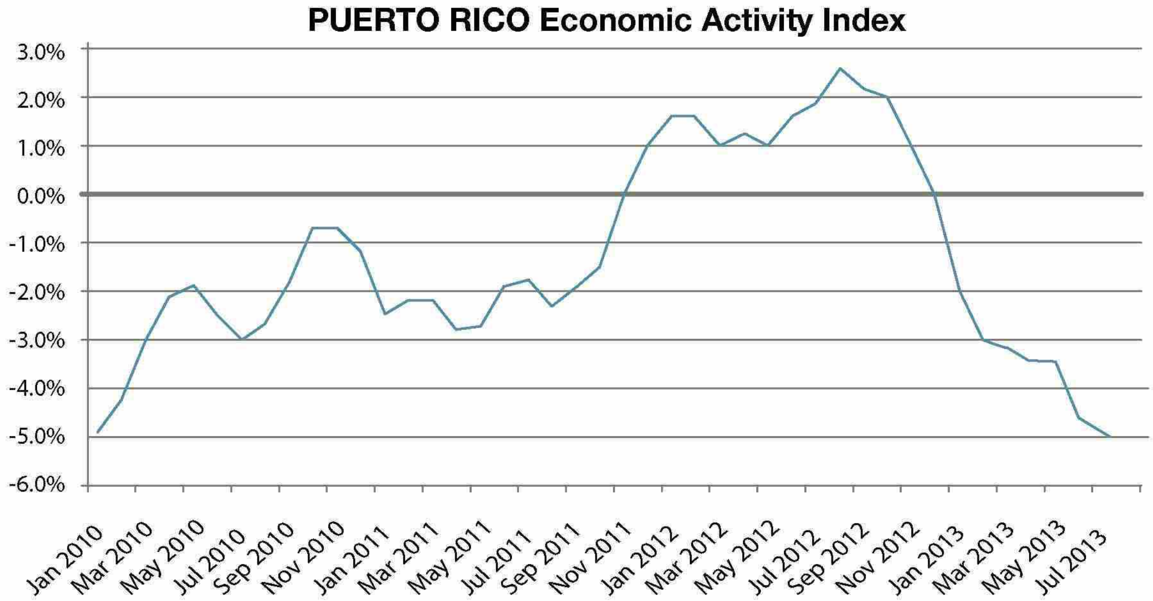
Since the present depressed state of the economy of Puerto Rico is unprecedented in recent history, economic forecasting for the island is currently difficult and more uncertain. The demand for electric energy in Puerto Rico has historically tracked the island's economy and its attendant economic development. Puerto Rico's economy has evolved from primarily an agriculture economy in the early 1900s to one dominated by manufacturing in the 1940s through the 1970s and, finally, moving to a mixed economy largely comprised of the manufacturing and service sectors over the past three decades.

According to census data the population of Puerto Rico declined 2.2% between 2000 and 2010. This was the first recorded drop in population on the island, but was consistent with the prolonged weak economy discussed below. Subsequent census data have shown the decline has continued at a steeper rate. The census data showed the population drop was due to a low birth rate and increased emigration; the population losses were disproportionately in urban areas and amongst the young and middle age. The rural population actually grew modestly in the same period. The trends from the census data indicate that 15% of the people were over the age of 65 years in 2010 and that portion is projected to continue growing. According to GDB statistics the 2012 estimated population growth rate was negative 0.44%, and the net migration rate minus 0.82 migrants per 1,000 of the population. A report issued by the Puerto Rico Planning Board attributed the declining birthrate to migration of the people in their child bearing years, an economy that discourages family growth, more women marrying later in life, the drop in population of those in reproduction age, and family planning policies.

According to a Puerto Rico Labor Department report the unemployment rate remained high at 13.5% in July 2013, but this was still less than the highest percentage of 16.9% in May 2010. The labor participation rate in July 2013 was 41 percent.

The Puerto Rico Government Development Bank's data published as of January 2013, states that the composition of the Puerto Rico Gross Domestic Product (GDP) by sector is as follows: manufacturing 48.6%; finance, insurance, and real estate 17.8%; services 12.7%; government 8.3%; trade 7.6%; transportation and utilities 2.9%; construction and mining 1.4%; and agriculture 0.7%.

The Planning Board is the official Commonwealth agency that collects and reports the macroeconomic indicators utilized in the Current Forecast, including the Gross Domestic Product (GDP), and the Gross National Product (GNP), of the Puerto Rico economy. As measured by the GNP the Puerto Rican economy was robust in the three fiscal years ending in 2005; subsequently the economy grew marginally by 0.5% in fiscal year 2006 and then began five years of decline with contractions of 1.2% in fiscal year 2007, 2.9% in fiscal year 2008, 3.8% in 2009, 3.6% in 2010, 1.7% in 2011 and finally positive growth of 0.9% in 2012. During the five fiscal years from 2007 to 2011 Puerto Rico's economy receded by over 12%, a magnitude not seen since the Great Depression. For fiscal year 2013 the Planning Board reports a marginal growth rate of 0.3%.



The Government Development Bank of Puerto Rico measures the island's economic activity with the Economic Activity Index (EAI). This index is similar to the Gross Domestic Product Index; it is keyed to four major local monthly economic indicators. As can be seen by the data, the GDB-EAI returned to growth in December 2011 which lasted approximately one year. This was the first period of growth since the island's economy recession began in 2006. The EAI maintained some positive growth on a 12 month rolling basis through calendar 2012, however the brief recovery ended at the beginning of calendar year 2013 and had declined by 5% in the next six months.

The Planning Board attributes the modest recovery in the economy of Puerto Rico during fiscal year 2012 to the moderate expansion of the U.S. economy, the additional revenue provided by the temporary excise tax on sales of Controlled Foreign Corporations manufacturing companies to affiliates, the additional Commonwealth revenue provided by the Tax Reform Act, a drop in the employee's social security tax rate, and an resurgence in demand in consumption and private investment in Puerto Rico.

ECONOMIC PROJECTIONS

The Current Forecast is based on econometric models which attempt to correlate the future consumption of electricity with recent consumption data, industrial sector power costs and selected historical and projected macroeconomic indicators. These macroeconomic indicators are: personal disposable income, used in part to forecast residential energy sales; GDP, used in part to forecast commercial energy sales; and GNP, used as a factor in forecasting industrial energy sales.

MACROECONOMIC PROJECTIONS

In the preparation of the Current Forecast the Authority typically incorporates analyses of the Puerto Rico economy that are prepared each year by three independent economic consultants. The forecasts prepared by the Commonwealth of Puerto Rico's Planning Board (Planning Board) were unavailable when the Authority performed its analyses for this year's Current Forecast. The Authority used the two forecasts that were available, which were the economic projections developed by the Inter-American University of Puerto Rico – IHS Global Insight (IAU-GI) and Advantage Business Consulting Group (ABC). A summary of the economic consultant's projections on the key indicators on the five-year outlook are as follows:

Puerto Rico Economic Indicator Projections
Five year Compound Annual Rate 2013-2018

	ABC	IAU-GI
Gross National Product	0.99	1.28
Personal Disposable Income	1.64	1.75
Gross Domestic Product	1.58	1.63

The key economic indicator projections correlate with the resultant predictions by the Authority for electric sales by major classification as described below.

In view of the uncertainties in the economic forecasts the Authority generally uses the least optimistic five-

year intermediate-term energy sales projections for financial planning purposes and the most expansive economic projections for capacity and operational planning. In the Current Forecast the Authority selected ABC's projections as the bases for its fiscal year 2014 annual budget as well as the financial projections through fiscal year 2018, yielding a five-year compounded annual growth rate (CAGR) of 1.22% in its electric energy sales model.

The expansive projections, those of IAU-GI, yielded a five-year CAGR of 1.43% in the Authority's electric energy sales model which were used in its load growth forecast for capacity planning.

For many years the short-term energy sales projections in the Authority's Current Forecasts were usually conservatively close to actual performance; these were during a period of almost continuous electric sales growth only interrupted by the impact of hurricanes. In fiscal year 2006, however, short-term consumption forecasts began to understate the actual decline in consumption. To improve the accuracy of its projections, in 2008 the Authority revised the modeling of residential and industrial sector consumption to reflect the clients' sensitivity to the price of electricity.

CURRENT FORECAST PROJECTIONS

In developing the Current Forecast the Authority uniformly employs the economic indicators from each economic consultant. The resulting projection of energy sales over the five-year intermediate term forecast period are summarized below:

TOTAL ENERGY (GWH) SALES PROJECTIONS

Fiscal Year	ABC	Annual Change	IAU-GI	Annual Change
2012	18,112.5		18,112.5	
2013	17,966.7	-0.80%	17,966.7	-0.80%
2014	18,199.0	1.29%	18,191.5	1.25%
2015	18,267.8	0.38%	18,431.2	1.32%
2016	18,476.0	1.14%	18,699.3	1.45%
2017	18,756.9	1.52%	18,988.1	1.54%
2018	19,090.6	1.78%	19,292.7	1.60%
5-yr CAGR		1.22%		1.43%

ABC's model dated April 2013 considered a wide range of factors while developing its economic forecast. As reported in the Current Forecast, these factors included the following exogenous variables: growth of the U.S economy of between 1.8% and 2.4%, the price of a barrel of oil (WTI) of between $103.25, an increase over the current price of $95.07; U.S. federal funds target rate of 0.25% until 2014 and 0.5% to 1.15% through 2018 and the 10-year treasury rate of 1.80% to 3.00%.

There were several endogenous variables considered by the ABC projections. Those listed are: that there would no further degradation of the Authority's power bonds to non-investment grade, that the fiscal austerity period would extend until 2014 or early 2015, very moderate growth in real public expenditures, public investment begins to recover vigorously after 2015, that in 2016 the elimination of the structural deficit of the central government would be achieved, and that the rate of inflation over the years of the projection would be controlled between 2.5% and 2.6%.

CONSUMPTION OF ELECTRICITY

Over the period from the mid-1980's through 2006, the annualized rate of growth in the consumption of electricity in Puerto Rico was generally greater than that of the U.S. mainland. Interruptions in this pattern were principally caused by major weather events. The event with the greatest impact occurred in 1998 when Hurricane Georges devastated the island, causing severe damage to the Authority's system and a dramatic, short-term curtailment in energy sales. By fiscal year 2000, however, the annual growth rate in the Authority's energy sales rebounded back to a robust 6.8%. The growth rates for energy sales in fiscal years 2001, 2002, and 2003, were moderate at 3.2%, 2.2% and 4.0% respectively. For fiscal years 2004 through 2007 the decline in the annualized growth rate for energy sales continued with marginal growth rates of 1.9%, 1.2%, 0.6% and 0.3%, respectively. For fiscal years 2008 and 2009 energy sales declined sharply resulting with negative growth rates of 5.2% and 5.5%, respectively. In fiscal year 2010, the negative trend in energy sales reversed when total energy sales increased by 3.9%, principally as a result of a 10.8% jump in energy sales in the residential sector. However, during fiscal years 2011 and 2012 energy sales continued the previous negative trend with declines of 3.8% and 2.1%. As discussed in the *Energy Sales Forecast* section, the reported energy sales for fiscal year 2013 show an increase of 0.6% over the previous year.

As shown on the comparative chart, Electric Retail Sales-All Sectors US & PR, the rate of growth in electric sales contracted in Puerto Rico and the U.S. mainland during 2008 and 2009. Both Puerto Rico and the U.S. mainland experienced robust electric sales

growth in 2010. However, as the U.S. mainland recovered from its recession electric utilities posted modest electric energy sales growth in 2011 and are projected to produce marginally positive electric energy sales growth less than 1% annually to 2018. Although the GNP of Puerto Rico increased marginally by 0.9% during fiscal year 2012, electric sales were off 2.1% from the previous year. For reference, the comparable statistics in fiscal year 2011 were a decline of 1.7% in the GNP and 3.8% decline in electric sales. In the Current Forecast the Authority projected a decrease in electric energy sales of 0.8% in fiscal year 2013, in contrast to the reported increase of 0.6%. The Current Forecast projects growth in electric energy sales in 2014 of 1.3%, followed by steady growth in the following four years from 0.4% in fiscal year 2015 to 1.8% in fiscal year 2018.

It should be noted that in the comparison chart the Authority's energy sales for fiscal year 2013 are the reported actual energy sales and preliminary electric energy sales replaced the forecasted energy sales for U.S. electric utilities in calendar year 2013. The forecasted percentage change for Puerto Rico in the subsequent year 2014, however, reflects the Current Forecast projected change. By updating the 2013 data for the US the percentage, the change to 2014 may be slightly different than that formally estimated or projected. The data for the U.S. mainland are derived from EIA's Annual Energy Outlook 2013 (AEO 2013), prepared in June 2013.

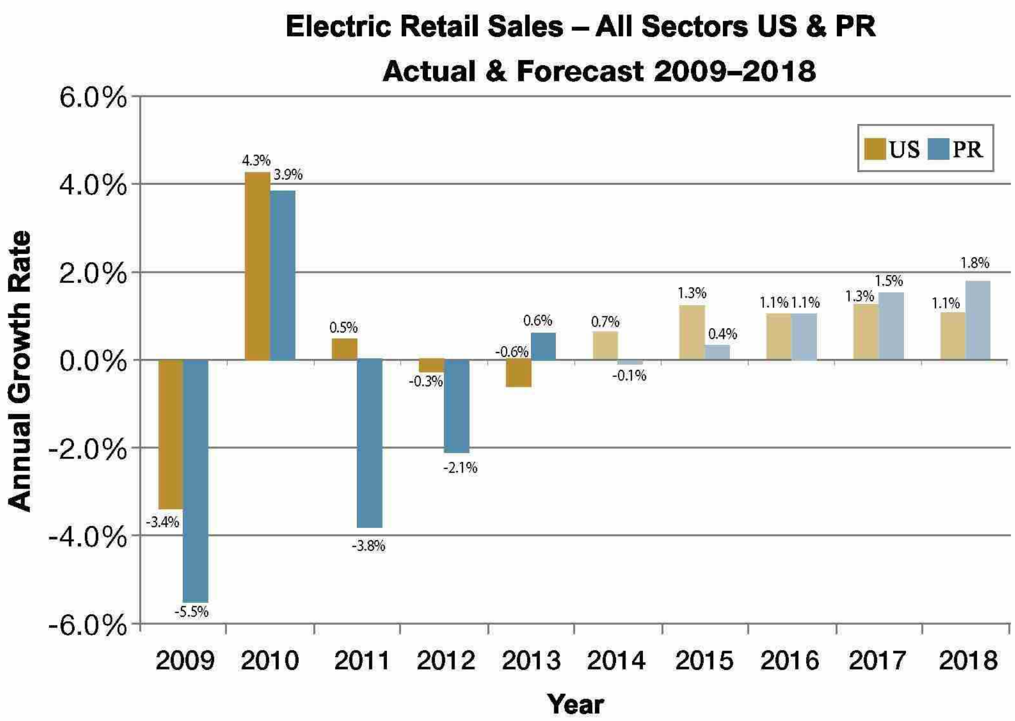
DEMAND AND ENERGY FORECAST

GENERATION FORECAST

The total net generation during fiscal year 2013, including hydro-power and power purchased from the cogenerators and renewable energy projects, was 21,009 GWh, which was a 0.9% decrease compared to that generated in fiscal year 2012. In 2014 the Authority projects that total net generation will increase by 1.4%. With the exception of fiscal year 2010, net generation has been in decline since fiscal year 2008, when it was 9.1% more than fiscal year 2013.

Electric generation projections in the Current Forecast track with forecasted sales. The contribution to the System of power from renewable energy projects is forecasted to grow from 0.7% in fiscal year 2013 to more than 4.5% of the total for the fiscal years 2015 through 2018. The growth of renewable energy projects will displace generation from the Authority's least efficient and most costly units. The Current Forecast projects a decline in net generation by the Authority of 1.8% in fiscal year 2015, followed by increases of 1.6%, 2.2% and 2.9 % in fiscal years 2016 through 2018.

Each year in the Current Forecast the Authority develops a ratio, referred to as the system efficiency, based on total energy sales as a percent of the total of the Authority's gross generation plus the net amount



of purchased power, which is the net output of the two cogenerators plus the output of the renewable energy projects. The annual generation for the forecast period was determined utilizing a system efficiency that was the System's 12-month average for the period ending February 2013, based on the sales and generation methodology in the Current Forecast. The actual and projected generation by plant are presented in *Appendix IV, Annual Net Generation, Fuel Consumption, Fuel and Purchased Power Costs.*

PEAK DEMAND FORECAST

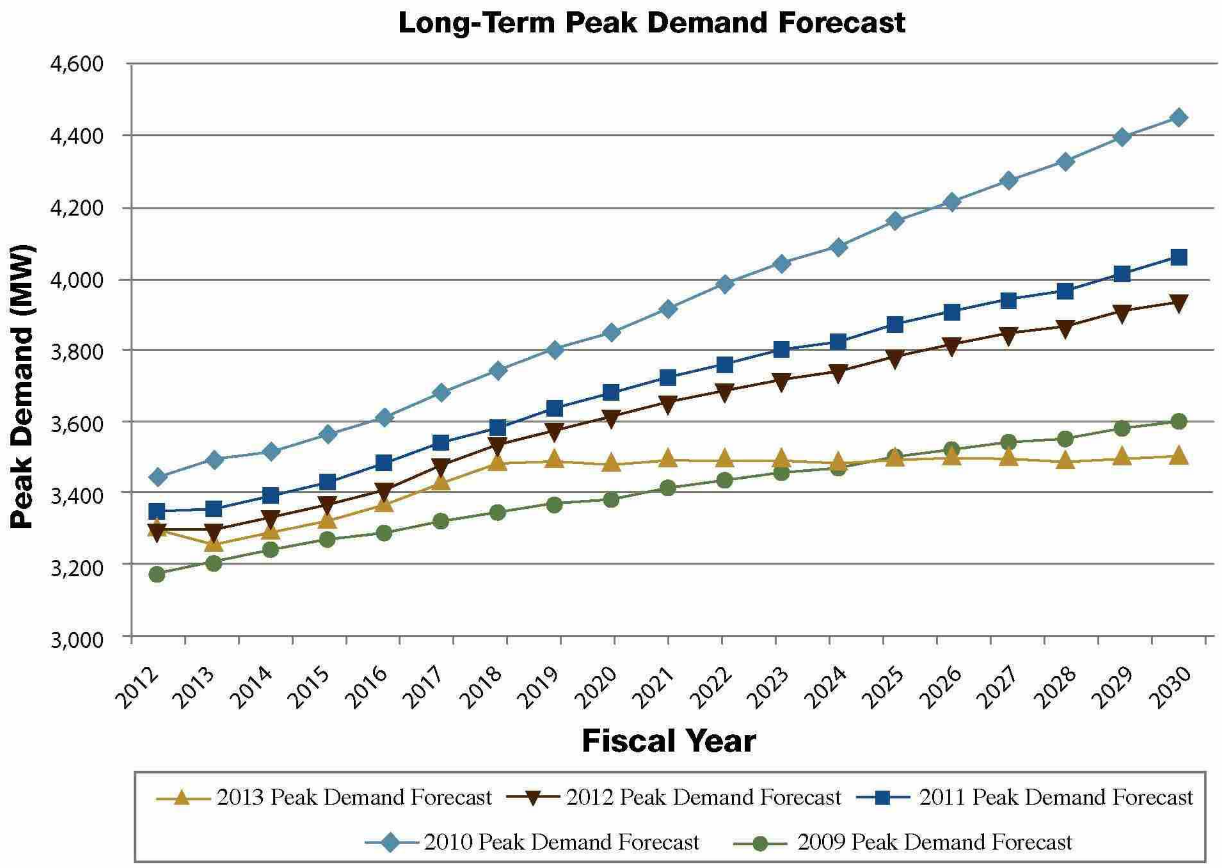
Consistent with the Authority's conservative approach to planning for expansion of generation capacity the Current Forecast used the projections that resulted in the most expansive forecast for the development of the peak demand forecast. For this year's Current Forecast the projections from IAU-GI met that criterion and were the basis of the peak demand forecast. For a comparison of the economic consultants kWh sales projections refer to the *Economic Projections* section above.

For the seventh consecutive year the System did not reach a new peak demand. The current historic system peak of 3,685 MW was established in September 2005, in fiscal year 2006. From fiscal years 2008 to 2013 the five-year compound average growth rate (CAGR) in actual peak demand contracted by 0.5%.

The peak demand for fiscal year 2013 was 3,265 MW was 1.2% less than that reached during fiscal year 2012 and 11.4% less than the historic system peak demand.

The Current Forecast utilized a system load factor of 77.2% to predict peak demand for the duration of the generation forecast. The system load factor is the ratio of the average demand in kilowatts supplied during a designated period, in this case the fiscal year through March 2013, to the peak or maximum demand also measured in kilowatts. The most expansive model in the Current Forecast predicts that the 3,685 MW peak demand established during fiscal year 2006 will not be exceeded during the duration of the long-term forecast. The forecast peak demand projects a CAGR growth of 1.4% for the five years through fiscal year 2018, with effectively no growth in peak demand for the balance of the forecast period.

Since 1993 the Authority has included explicit recognition of the potential effects of its DSM & EC programs in its peak demand forecasts; these programs are discussed below. The Long-Term Peak Demand Forecast graph shows the degree in which the peak demand forecast has declined over the last four years.



DEMAND-SIDE MANAGEMENT AND ENERGY CONSERVATION PROGRAMS

Electric utilities offer programs to encourage clients to modify their levels and patterns of electric consumption. The implementation of such programs, known collectively as Demand-Side Management & Energy Conservation (DSM & EC), achieve two objectives; energy efficiency and load management. DSM initiatives such as load management programs are designed to shift load from peak hours to nonpeak periods. Energy efficiency measures reduce the energy consumption of end-use devices and systems by promoting high-efficiency equipment and energy efficient building design. Successful DSM & EC programs promote energy efficiency and achieve cost-effectiveness for utilities and clients thereby delaying the need for new capacity. DSM & EC programs help to conserve fossil fuel resources, reduce air pollution, and lower a utility's need for additional capital and its carrying costs.

As part of its Load Management Program the Authority promotes: Time-of-Use (TOU) rates to improve or smooth out its load curve; the purchase of energy-efficient motors and air conditioners; and the use of more efficient lighting. TOU rates offer economic incentives to Industrial and Commercial clients who modify their patterns of energy consumption, i.e., adding load to off peak hours and reducing load during peak hours. (For more information on TOU rates see the *Rates* section.) The Authority, with a limited staff, also offers advice to clients on power factor improvement that benefits both the client and the Authority.

During recent years the Commonwealth Government's Energy Affairs Administration (EAA) has promoted a succession of programs and incentives promoting cost effective energy saving. These have ranged from encouraging the replacement of incandescent light bulbs with compact fluorescent bulbs to voucher initiatives that subsidize purchasing energy efficient home appliances. The EAA has been active in encouraging projects to access federal grant money through the stimulus funding from the American Recovery and Reinvestment Act and the Department of Energy's "Energy Efficiency and Conservation Block Grant" (EECBG) program. Some EECBG grants, such as light bulb exchange programs, are also directly administered through larger cities. In addition to weatherization projects for the private sector and vouchers for high efficiency appliances, the EAA has promoted energy savings agreements between public agencies and a specialized private company for the installation of energy savings equipment with a provision that the savings in energy costs would be shared between the two entities.

In February 2013 the EPA and the Commonwealth announced new guidelines for energy efficient homes in Puerto Rico. These guidelines, developed by the EPA under the federal Energy Star program, were formulated based on Puerto Rico's Caribbean climate to establish energy efficiency standards and practices for local home construction. The goal of the energy efficient homes is to identify features that will reduce energy use by an estimated 20 to 30% compared to standard homes. The efficiency features include: high quality energy efficient windows; efficient systems for heating, ventilating and cooling; comprehensive water management systems to protect floors, walls and foundations from moisture damage; and energy efficient lighting and appliances.

The Commonwealth government created a Green Energy Fund following passage in 2010 of the Puerto Rico Green Energy Incentives Act. The six-year program began in fiscal year 2012 with a budget of $20 million for each of the first two fiscal years and $25 million in fiscal year 2014. The fund is structured to provide grants to business and homes that invest in renewable energy technologies such as photovoltaic, wind, and renewable biomass combustion. Under the Green Energy Fund incentives are available for up to 60% of the eligible costs for small renewable energy projects, and up to 50% for larger projects. The incentives do not apply to an installation which generates power that exceeds it internal requirements as defined based on the technology.

The Authority, as it has for the past several years, projects that the savings from its DSM & EC program will lower peak demand by 1 MW per year (see previous section).

The Authority is evaluating its long term metering plans to potentially expand the operational features of its automated meter reading system to include a load control component. This feature would increase the impact of load reduction by allowing the Authority to control clients' equipment, such as air conditioners, for periods when load management is desirable.

CAPACITY AND ENERGY RESOURCE PLANNING

OVERVIEW

The Authority periodically updates its Capacity Expansion Plan (CEP) to ensure its ability to meet expected long term electric load growth with reliable, cost effective and environmentally compliant electric power. To address cost and reliability, the Authority employs system-planning software that is widely accepted throughout the electric utility industry.

Consistent with its goals to provide reliable, cost effective electric energy the Authority has also pursued fuel diversification for many years, with the primary focus being on increasing the utilization of natural gas in its production plants. Conversion of oil fired production plant to dual fuel firing of natural gas and / or oil would both reduce air pollution and provide the Authority's ratepayers with reduced electric energy costs.

As discussed in the *Environmental* section, regulations issued by the EPA in fiscal year 2012 have added other imperatives for the Authority to reduce its dependence on fuel oil and switch to natural gas for electric generation. The Authority's environmental compliance strategy involves dual fuel firing conversion at its eight largest steam plants. By the end of the past fiscal year the two 410 MW units at the South Coast plant were capable of full firing on natural gas, which was purchased by the Authority from the nearby regasification facility at the EcoEléctrica cogeneration plant. The development of the natural gas supply infrastructure is discussed in the *Energy Resource Planning* section below.

AVAILABILITY

Over the last two decades the Authority has directed much of its production capital expenditures on improvements to extend the life of its generating facilities, reduce the need for extended scheduled outages, and lower the frequency of forced outages, thereby increasing the percentage of time its generating units are available for service. As the Authority's dual fuel conversion strategy has been implemented the largest units have been through extended outages to implant the scope of required work.

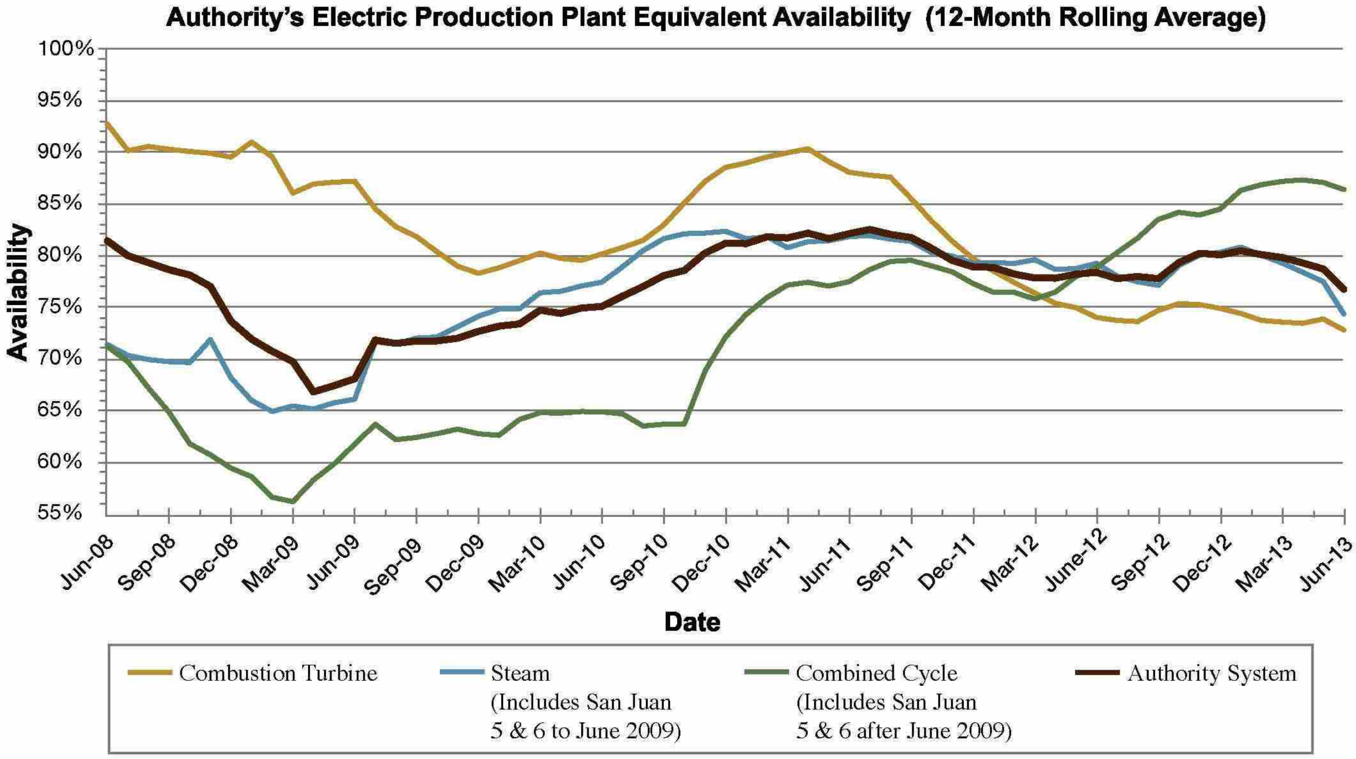
Since the availability data reflect accumulated performance over the preceding twelve months, an extended outage of a large unit can impact the system data well beyond its return. This was observed following the outages at the Palo Seco plant due to fires. During fiscal year 2010 the Palo Seco units were fully restored to service. The availabilities of both the steam plant and total system steadily increased during fiscal years 2010 and the first half of 2011 reaching 82%, as routine maintenance at other plants that had been delayed while the Palo Seco outages were performed.

In October 2011 the Authority removed the 450 MW Aguirre Unit 1 from service for a major overhaul and to perform initial boiler modifications for its conversion to dual fuel firing. Later in 2012 the 410 MW South Coast Unit 6 was removed from service for final boiler conversion modifications, allowing the unit to increase its gas firing capability. The removal from service of these large generating units reduced total system availability to 78% from December 2011 through September 2012, after which availability increased again to 80%. In January 2013 the 410 MW South Coast Unit 5 was removed from service for the final boiler conversion upgrades similar to that of South Coast Unit 6, reducing total system availability to 77% by the end of fiscal year 2013. Concurrent with extended outages for dual fuel conversion work, the Authority has adopted the policy of avoiding overtime for scheduled outages to reduce their costs. This work practice has extended the duration of these outages and negatively impacted availability.

The Authority's overall production plant equivalent availability for the five-year period ending June 30, 2013 is shown in the chart based on rolling twelve month data. Performance is shown by the Authority's total system and by the three major kinds of generation — steam, combustion turbine, and combined cycle. Prior to fiscal year 2010, the availability of San Juan Units 5 & 6 was included with the steam portion of the system. Beginning in fiscal year 2010 San Juan Units 5 & 6 were tracked in the combined cycle group.

CAPACITY PLANNING

The Authority's current capacity expansion plan is based on the Authority's most recent Current Forecast dated April 2013. Based on these projections the previous peak demand will not be exceeded within the horizon of the Authority's capacity planning. The Current Forecast foresees relatively modest increases in peak demand averaging 0.7% per annum over the first ten years of the forecast period. The previous system peak was 3,685 MW, established in fiscal year 2006; in fiscal year 2013 the peak was 3,265 MW. The Current Forecast projects the peak demand in ten years will be 3,499 MW and the previous peak will not be exceeded even within the long term horizon of the Authority's forecast.



Details of existing generating capacity of the System are shown in *Appendix VIII, System Capability.* The Authority does not plan to add or retire capacity through fiscal year 2018.

The Authority has numerous proposed renewable energy projects under power purchase agreements, however, none meet the criteria for firm and reliable capacity therefore these projects are recognized as only sources of energy; this is also consistent with their characteristically low capacity factor.

PURCHASED POWER

In parallel with the internal program to improve production plant performance, the Authority entered into long-term purchased power operating agreements with the owners of two privately owned and operated cogeneration facilities. These relatively new plants were selected to aid the Authority in providing for electric load growth. They reduce the island's dependence on fuel oil, and continue to improve the System reliability.

Prior to the Authority purchasing power from the cogenerators, nearly 99% of the energy sold by the Authority was produced by its oil-fired units. In fiscal year 2013 the cogenerators produced 33.7% of the System total power. Subject to dispatch and actual availability, the combined generation of EcoEléctrica, L.P. and AES-PR is forecasted to be 33.3% of the total System generation in fiscal year 2014.

In accordance with a 22-year power purchase operating agreement (PPOA) that commenced in March 2000, the Authority has been purchasing 507 MW of power produced by EcoEléctrica, L.P.'s gas-fired combined-cycle cogeneration facility. The PPOA outlines capacity and energy charges to be paid by the Authority based on the performance and electrical output of the facility. A principal condition of the agreement is a progressive reduction in the monthly capacity charge, paid by the Authority, subject to the facility meeting a minimum 93% availability on a 12-month rolling average. EcoEléctrica's availability during fiscal year 2013 was 91.4%, down from 95% in the previous year. In fiscal year 2013, EcoEléctrica, L.P. represented 8.6% of the System's capacity and provided 17.0% of its power. For fiscal year 2014 the energy provided to the Authority's from EcoEléctrica is forecast to be 17.5% of the System total.

The Authority also has an agreement with AES-PR to purchase 454 MW of power from its coal-fired steam-electric plant. The plant, which consists of two identical fluidized-bed boilers and two steam turbines, uses clean coal-burning technology. The facility commenced commercial operation in November 2002. The 25-year PPOA with AES-PR is similar to EcoEléctrica, L.P.'s. The minimum guaranteed availability for AES-PR is 90%, slightly lower than EcoEléctrica, L.P.'s, but typical of coal-fired electric generating plants. The availability of AES-PR for the 12 months ended June 30, 2013 was 91.1%; its avail-

ability was 87.4 % during fiscal year 2012. Although AES-PR comprises 7.7% of the System's capacity, this cogenerator provided 16.7% of its energy during fiscal year 2013. It is anticipated that the plant will provide 15.8% of the System's total generation in fiscal year 2014.

These PPOA's have allowed the Authority to reduce its dependency on fuel oil, mitigate the economic risk of its electric system operation, and to schedule the retirement of some of its older, less efficient generating units. For further discussion on EcoEléctrica and AES-PR, refer to the Cogenerators in the *System's Operation* section.

The operating agreements with both cogenerators include provisions for fixing the cost of fuel used to generate electricity for each year of the contract at the beginning of such year. Annually, the fuel portion of the energy charge per kWh is based on actual fuel-related energy charges for the preceding year, adjusted using inflation and other indices. The fixed nature of the fuel cost reduces short-term variations in the Authority's energy costs by bringing purchased power costs out of step with price changes in other components of the Authority's fuel mix. The fixed fuel costs also afford the Authority the opportunity to better dispatch its electric production plant.

ENERGY RESOURCE PLANNING

With the prospect of adequate generation reserves for many years, the Authority's focus has been on developing an environmental compliance program discussed in the *Environmental* section, while reducing and stabilizing future electric power costs, by decreasing its dependence on oil. The Authority has identified the first step in this process is to expand its use of natural gas, which would be supplied to the island as liquefied natural gas (LNG). Typically the price structure of LNG provides more stable energy prices in comparison to oil. The availability of competing, alternative fuels may also benefit the Authority in its negotiations with fuel suppliers.

The Authority's first proposed program to expand gas firing was a planned gas pipeline on the island's south coast from the LNG regasification facility at the EcoEléctrica cogeneration plant in Guayanilla to the Authority's Aguirre plant approximately 40 miles to the east. The first units scheduled to use the surplus gas capacity from EcoEléctrica were the two existing 296 MW combined cycle units at the Aguirre plant, which had been converted to dual fuel capability. The pipeline project had raised significant local opposition and controversy from its inception. Construction on the pipeline was in its early stages when the Commonwealth decided to terminate the project in 2009.

The Authority subsequently developed a broader program to expand natural gas firing in its units. This program was based on a pipeline from the LNG regasification facility at the EcoEléctrica cogeneration plant to certain Authority plants on the north coast. The proposed 92 mile long pipeline route was north through the island's interior and then east to the San Juan area. By fiscal year 2012 the Authority had made significant progress in the permitting process, during which the Authority responded to numerous recommendations with respect to routing, safety and environmental mitigation. As the completion of the permitting process drew near, the US Army Corps of Engineers, who were the lead permitting agency, extended its review after several federal agencies submitted additional concerns or revised comments. During this period contentious opposition to the pipeline within the Commonwealth continued to grow; in addition, it was determined that the proposed pipeline would not have enough capacity to support the Authority's compliance with the MATS environmental objectives.

In view of the seriousness of the situation, as discussed in the *Environmental* section, the Commonwealth's government appointed a select committee presided over by the chairman of the Environmental Quality Board of Puerto Rico to evaluate the alternatives for compliance with MATS. The committee concurred with the Authority that conversion from oil to natural gas was the best method. The committee's general recommendations included employing one or more offshore regasification and delivery systems for LNG, but acknowledged other technologies such as compressed natural gas (CNG) should be considered. The 92 mile pipeline project was judged to be not viable, due to constrained capacity, projected cost escalation and community opposition.

After cancellation of the southern pipeline to Aguirre, the Authority decided to utilize the excess gas storage capacity which it was leasing at EcoEléctrica by converting the boilers at the 410 MW Costa Sur Units 5 & 6 to dual fuel. These units were selected because of their proximity to the LNG facility, resulting in a short pipeline from EcoEléctrica to the Costa Sur plant and the relatively low capital cost and short schedule to convert the units to dual fuel. During fiscal year 2011 the Costa Sur Units 5 & 6 were converted to dual fuel burning capability. Since then the units have operated with at least partial gas firing.

Subsequently the boiler internals were modified to support continued full load operation with all gas firing; this work was performed for Unit 6 during fiscal year 2012 and completed for Unit 5 at the end of fiscal year 2013.

The quantity of natural gas available to Costa Sur from EcoEléctrica has been constrained under the terms of the short term fuel purchase agreement which is scheduled to expire late in fiscal year 2014. The maximum quantity of fuel had been based on the capacity of the regasification facility. During fiscal year 2013 EcoEléctrica installed and made operational two additional regasifiers. Under their FERC permit EcoEléctrica regasification capacity enables it to provide sufficient gas for its own consumption as well as Costa Sur Units 5 & 6 at approximately 55% capacity factor. Additional gas production is possible with the installed equipment, however this would require a revised FERC permit.

The Authority's current approach to expand the supply of natural gas on the island has been an offshore gasification facility for LNG deliveries near its Aguirre power complex on the southeast coast. The proposed Aguirre Offshore Gas Port (AOGP) will be a floating facility to receive and gasify LNG shipments. The natural gas will be delivered to the Aguirre plant by pipeline from the AOGP. The Authority plans that the AOGP will be installed by a vendor under a long term agreement and the Authority has continued with the coordinated air permit effort with that vendor for both the AOGP scope and the Aguirre plants. The proposed schedule at the end of fiscal year 2013 would enable gas to be available for the Aguirre plant by the MATS compliance date of April 2015, with no margin for unanticipated delays.

During fiscal year 2013 the Authority continued its due diligence on the contractual structure of the gas supply infrastructure and was evaluating alternative supply arrangements for natural gas to the north of the island. The Authority is evaluating the structure of the LNG commodity supply agreements, which would be separate from the infrastructure development. The Authority plans to select the bases for establishing the development of the natural gas infrastructure and fuel supply during fiscal year 2014. These will lead to qualifying bidders and soliciting proposals by the end of that fiscal year.

The Authority has focused first on its four largest steam units for dual fuel conversion on the south coast. The four steam units in the San Juan metropolitan area will be converted after the schedule for gas deliveries has been established. With sufficient fuel being available the Authority plans to add gas firing capability to the Authority's two most efficient units, San Juan Units 5 & 6, which are combined cycle units presently burning high cost distillate fuel.

ALTERNATIVE ENERGY SOURCES

To promote the use of renewable resources for the production of electric energy and further expand energy diversification, the Commonwealth passed Act 82 in 2010 that established new initiatives to strongly encourage the development and implementation of renewable energy sources in Puerto Rico. The legislation effectively sets a target renewable portfolio standard that requires an increasing percentage of retail electric power be provided from renewable energy sources. The initial target calls for 12% of total energy sales should be from renewable energy production by the end of calendar year 2015, increasing to 15% by 2020 and 20% by 2035. These targets are premised on the basis that the renewable energy projects will not compromise the continued safe and reliable operation of the island's electric system. The legislation creates a financial incentive to meet these standards by establishing Renewable Energy Certificates that can be sold if the standards are exceeded or must be purchased if the standard is not met.

As more renewable energy projects have entered service the electric utility industry has been analyzing the impact of these intermittent resources on system operations and stability. The Authority has performed similar screening studies to evaluate the impact on their System operation which is inherently more susceptible to disturbances given that as an island they lack an interconnected external transmission and generation network. To corroborate earlier studies, the Authority plans to perform refined analyses during the coming fiscal year; the analyses will identify the maximum generation from projected renewable energy resources that can be accommodated by the System. As the percentage of renewable capacity increases within the System, the inherent uncertainty of these sources imposes conditions on reserves and economic dispatch which could increase overall system electric production costs. Also the electrical characteristics of some renewable technologies affect the transmission and distribution of electric energy requiring the implementation of mitigating technologies to maintain electric system stability. In 2012 the Authority revised their minimum technical requirement (MTR) standard, which establishes the technical parameters for integration of renewable projects into the Authority's electric system.

In the past fiscal year the Authority began renegotiating its agreements with many renewable energy project developers to lower their energy costs to the Authority and incorporate the revised MTR. This has been an on-going process that applies to all new projects as well.

As of the end of fiscal year 2013 the Authority had signed a total of 63 power purchase agreements from renewable energy projects with a total capacity of 1,661 MW. All of these agreements are for only energy. As tabulated, few of these were in operation by the end of fiscal year 2013. The preponderance of the pending projects had not begun construction by the end of the past fiscal year. The total energy from the operating renewable sources accounted for 0.7% of the System total during fiscal year 2013. The Authority projects the contribution from renewables will increase to 4.7% by fiscal year 2015, where it will stabilize at that level through 2018.

RENEWABLE ENERGY PROJECTS STATUS FISCAL YEAR 2013

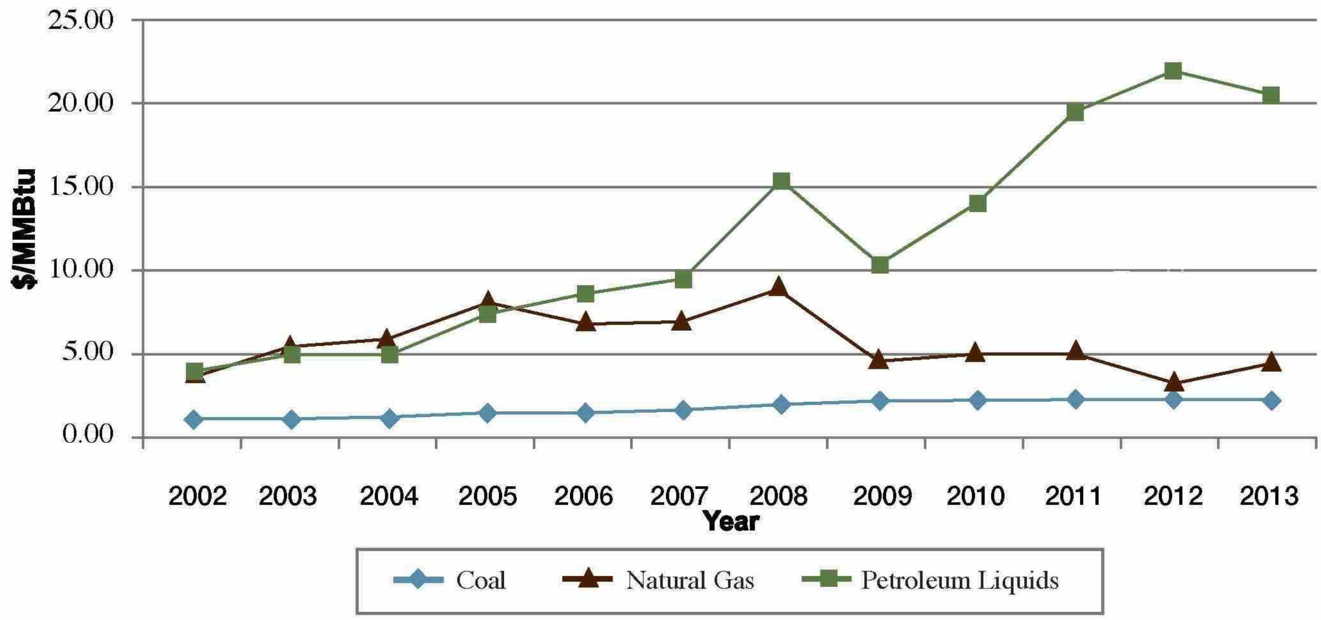
Category	Number of Projects	Associated Capacity	Operating Projects	Associated Capacity
Wind	10	382.9	3	102
Solar Photovoltaic	46	1157.4	2	22.1
Landfill Gas	4	11.5		
Waste-to-Energy	3	109.0		
Total	**63**	**1660.8**	**6**	**124.1**

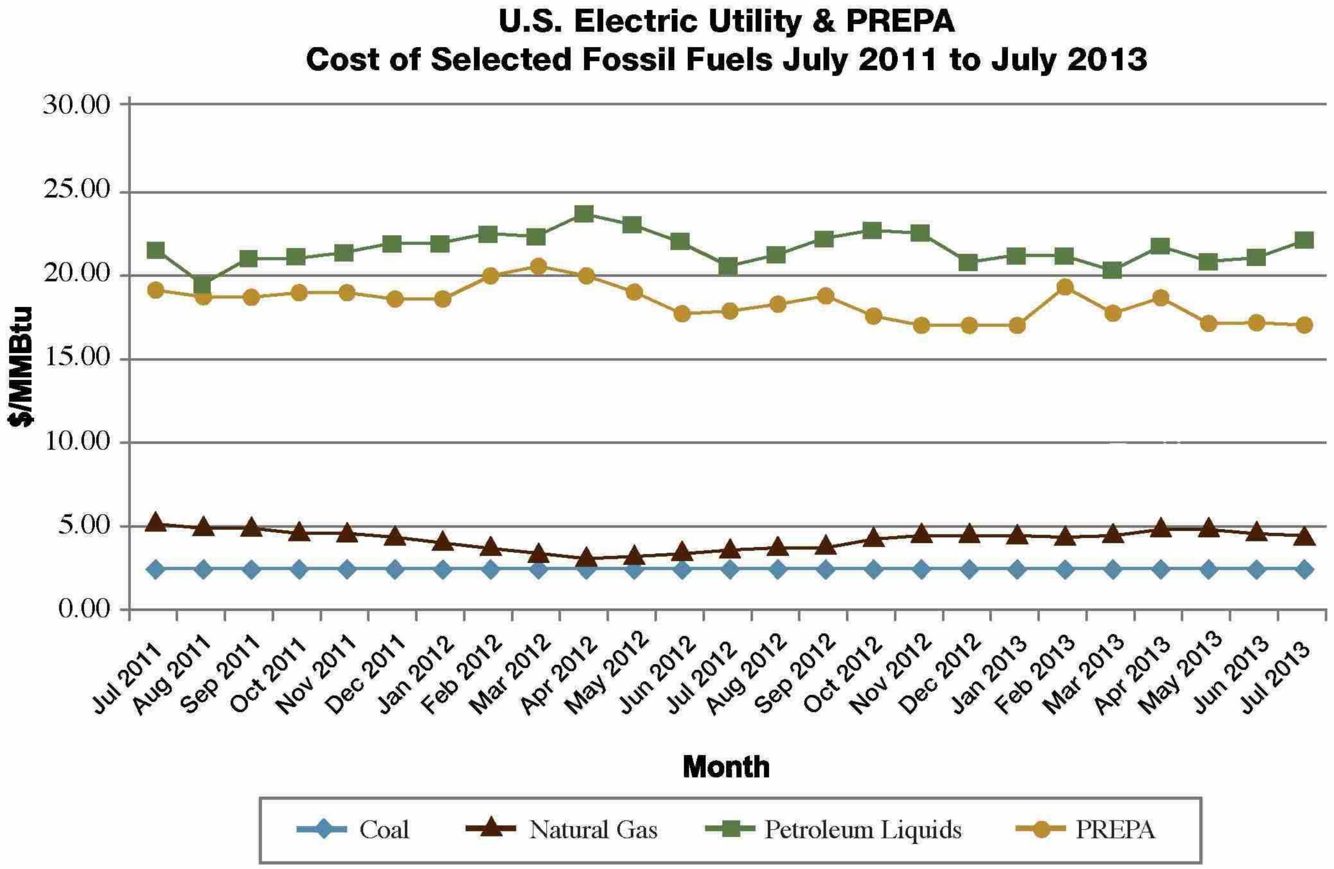
Fiscal year 2013 marked the first year during which renewable energy sources contributed meaningful amounts of the energy transmitted and distributed within the System. During fiscal year 2013 the Authority purchased energy principally from four renewable energy projects; an additional small wind turbine provided power occasionally.

The largest capacity renewable source was the Pattern wind farm in Santa Isabel, in the southeast of the island. Its initial capacity was planned for 75 MW; pending certain changes it is anticipated that the facility will operate at 95 MW seven months of the year and 75 MW for the balance. The second large wind farm provides 26 MW from the Punta Lima facility in the east of the island near Naguabo. Both wind turbine facilities began commercial operations in December 2012. Finally, the Authority installed a 1 MW wind turbine in the Bechara section of San Juan that went into operation late in fiscal year 2012. The turbine is located at a PRASA (Puerto Rico Aqueduct and Sewer Authority) facility which uses basically all the output.

During the past fiscal year the largest solar photovoltaic facility on the island was the 20 MW solar project in Guayama, on the south coast. This plant began commercial operation in October 2012. The 2.1 MW Windmar Cantera Martinó solar facility in Ponce began operations at 1.7 MW in 2011 and expanded in October 2012.

U.S. Electric Utility Costs
Cost of Selected Fossil Fuels 2002 - 2013





FUEL MIX

For information on the types of fuel used in the Authority's various generating units see the *Fuels* section under *System's Operations*.

The mix of generation by energy type for the Authority's System during fiscal year 2013 consisted of 54.4% being oil generated, 10.8% from natural gas at the Authority's Costa Sur plant, 17.0% from natural gas at the EcoEléctrica's facility, 16.7% from AES's coal burning facility, and 0.4% from the Authority's hydroelectric plants. The amount of power generated from natural gas in fiscal year 2013 totaled 27.8%, up from 18.9% in the previous year. Fiscal year 2013 marked the first year during which the renewable energy projects produced meaningful quantities, with 0.7% of the System's generation.

As discussed in the *Fuels* section in *System's Operations* the Authority regularly purchases its fuel oil under one year contracts that include provisions for extension. These contracts are structured to reflect physical clearing prices, and avoid speculation in the market. Frequently the Authority uses various strategies such as fixed price contracts and commodity hedges to minimize fuel cost volatility. In addition, the pricing structures of the two cogenerators are based in part on annual indices to provide stable pricing for purchased power. These strategies, however, do not isolate the Authority from changes in energy costs in the global market; all production related fuel expenses are currently recovered through the fuel component of the adjustment charge.

The total projected use of each type of fuel—residual or distillate oils, natural gas and the production from the cogenerators and renewable energy projects—is based on the generation required to meet the energy demand forecasts which are developed in the Current Forecast, as discussed above. The contribution to the System of power from renewable energy projects is forecasted to grow from 0.7% in fiscal year 2013 to more than 4.5% of the total for the fiscal years 2015 through 2018. Since the Authority is obliged to always take the power from the renewable energy project, except in unusual circumstances, the growth of renewable energy projects will displace generation from the Authority's least efficient and most costly units. The Authority utilizes an economic dispatch simulation of all generating sources in the System to determine the lowest cost generation plan. This dispatch simulation takes into account the heat rate, operational characteristics and fuel costs specifically for each plant. As discussed in the *Current Forecast* section, this information was developed for the remaining months of fiscal year 2013 and summarized annually for the five-year intermediate-term

forecast through fiscal year 2018. The actual annual results of generation, fuel use and costs for fiscal year 2013 and those forecasted over the five-year period are presented in *Appendix IV, Annual Net Generation, Fuel Consumption, Fuel and Purchased Power Costs.*

Although the data in the charts of the costs of selected fuel for utilities are based on mainland electric production facilities, the oil and coal pricing are indicative of trends applicable to Puerto Rico. The charts show the variations in the cost of selected fossil fuels on an MMBtu basis as reported to the Energy Information Administration's (EIA), the reporting arm for the Department of Energy; the first chart is on an annual basis from 2002 to 2013, the second shows monthly data from July 2011 to July 2013. It should be noted that the natural gas data in the chart reflect pipeline gas, while the only natural gas available in Puerto Rico is liquefied natural gas (LNG), which has a different and higher pricing basis. This differential in price would be due to the high capital costs of infrastructure to liquefy, store and regasify the LNG, specialized transportation vessels and the energy consumed in its liquefaction, transportation, storage and regasification.

AUTHORITY'S FUEL

The Authority's average composite cost of fuel, including transportation and fuel-handling costs and the cost of the fuel line of credit, in fiscal year 2013 was $111.18 per barrel. The composite barrel cost is based on the total cost of all the petroleum burned by the Authority, both distillate and residual oils, plus natural gas, which is equated to distillate on the basis of distillate's nominal heating value in terms of MMBtu per barrel. During fiscal year 2013 natural gas was burned only at Costa Sur Units 5 & 6. The total costs of fuel for fiscal year 2013 and the five-year forecast period are shown in *Appendix III, Detail of Operating and Maintenance Expenses.* During fiscal year 2012 the Authority entered into a Commodity Swap Agreement that provided protection against increases in the price of No. 6 fuel oil. The premium for the swap was $29.2 million, which is being amortized from June 2012 to October 2013. The payout to its counterparties amounted to $21.9 million in fiscal 2013 and $141,500 in fiscal year 2012.

Based on the Current Forecast, the Authority's estimated costs of fuel per barrel excluding finance charges, fiscal years 2014 through 2018 are forecasted to be $95.25, $94.67, $88.71, $87.27 and $80.94, respectively. The projected composite average fuel costs per barrel include natural gas, equated to distillate as described above. The forecasted prices of fuel are based on EIA indices for the types of fuel oil the Authority burns adjusted for the Authority's location and incidental charges. The composite fuel cost is based specifically on the mix the Authority has forecasted to be utilized in its generating units. The forecasted dispatch and fuel use are shown in *Appendix IV, Annual Net Generation, Fuel Consumption, Fuel and Purchased Power Costs.*

In forecasting the price per barrel of all fuel oil the Authority adds $0.40 for transportation and handling, and also approximately $0.40 for the interest on the Authority's fuel credit line and a Commonwealth tax of $3.36 is also added to the cost of distillate fuel oil. These projected fuel costs were used to develop the annual costs of fuel and the fuel adjustment revenues in the Authority's Current Forecast (See *Appendix I, Intermediate-Term Financial Planning Forecast*).

Including rented fuel storage tanks, the Authority has continued to maintain a 30 day inventory of fuel oil. It is noteworthy that the Authority has never had to curtail electric service from fuel oil shortages or from problems delivering fuel to its generating facilities.

ENERGY SALES FORECAST

The Authority's annual Current Forecast contains detailed projections of short-to-intermediate-term energy sales and revenues. The methodology and results of the Current Forecast are discussed in the *Current Forecast* section above. In summary, the Authority typically chooses the least expansive or most pessimistic projection over the intermediate five-year period for its financial forecast to account for the uncertainties inherent in economic forecasting. The Authority generally uses projections from three economic consultants. However, as was the case last year, the Puerto Rico Planning Board's projections were not available during the development of the Current Forecast, therefore only two economic consultants projections were used. Each consultant forecasts three key macroeconomic indicators—Gross Domestic Product, Gross National Product and Personal Disposable Income— which are used with other variables to project the intermediate-term electric sales, revenues and number of clients.

The energy sales reported for fiscal year 2013 reflect certain adjustments. These were principally carried forward from the last three months of fiscal year 2012 when the new customer and care billing system went into initial operation. While these adjustments did not affect revenues, they increased the reported energy sales in fiscal year 2013. Taken together, the adjustments increase reported total energy sales for fiscal year 2013 by 1.4%. The bulk of the adjustments were in the industrial class. The projections developed in the Current Forecast did not take into account these adjustments for fiscal year 2013, to avoid skewing the data for the base year of the forecasts. In the balance of this Annual Report, however, the energy sales reported for fiscal year 2013 reflect these adjustments.

The projected numbers of clients in the residential class are based on an econometric model using regression analysis. For the commercial class the econometric model for number of clients uses logarithmic regression analysis as a function of gross domestic product and population. The industrial class has a relatively low number of clients and the forecasted change in the number of clients was based on extrapolation of recent years.

SHORT-TO-INTERMEDIATE TERM ENERGY SALES FORECAST

In three out of the last five fiscal years there has been a contraction of energy sales. The reported total energy sales in fiscal year 2013 increased 0.6 % from the previous year with Residential increasing by 1.5% and Commercial increasing by 4.0%; the two remaining sectors decreased, with Industrial down by 7.2% and Other by 25.8%.

As shown in the summary table, total sales for fiscal year 2014 are projected to increase by 1.3%. The Current Forecast predicts the positive trend will continue with growth of 0.4% in fiscal year 2015, 1.1% growth in 2016, 1.5% in 2017; and 1.8% growth in 2018.

Last year's Current Forecast projected that energy sales would increase at a CAGR of 0.9% over the five-year period ending in fiscal year 2017. Based on the Current Forecast for fiscal years 2014 through 2018 electric energy sales are expected to increase with a CAGR of 1.2% over the five-year period.

The projected energy sales through fiscal year 2018, taken from the Authority's Current Forecast, are summarized in *Appendix I, Intermediate-Term Financial Planning Forecast.*

The table for Short-term Energy Sales Forecast data shows kilowatt-hour sales and percent change from the prior year by major client classifications for fiscal years 2012 and 2013. It also shows the forecasted percent change and kilowatt-hour sales from the prior year by major client classifications for fiscal years 2013 and 2014 taken from the Authority's respective Current Forecasts.

SHORT-TERM PLANNING AND FINANCIAL FORECAST
(Million of kWh)

	FY 2012 Actual	FY 2013 Forecast[1]	FY 2013 Actual[2]	FY 2014 Forecast[3]
Residential Sales	6,559.6	6,481.5	6,655.6	6,929.6
Annual Increase (Decrease)	*(2.2%)*	*(0.8%)*	*1.5%*	*2.4%*
Commercial Sales	8,300.1	8,417.8	8,635.2	8,591.1
Annual Increase (Decrease)	*(2.9%)*	*(0.3%)*	*4.0%*	*1.5%*
Industrial Sales	2,778.5	2,678.3	2,578.4	2,337.5
Annual Increase (Decrease)	*(3.6%)*	*(2.6%)*	*(7.2%)*	*(2.2%)*
Other Sales[4]	474.3	354.5	352.0	340.8
Annual Increase (Decrease)	*31.3%*	*0.0%*	*(25.8%)*	*(1.6%)*
Total Sales	18,112.5	17,932.0	18,221.2	18,199.0
Annual Increase (Decrease)	(2.1%)	(0.8%)	0.6%	1.3%

1. From May 2012 Current Forecast
2. Includes adjustments
3. From April 2013 Current Forecast
4. Other Sales are comprised of Agricultural, Other Public Authorities, and Public Lighting

The energy sales statistics for the U.S. cited in the following discussions are taken from EIA reports: Annual Energy Outlook 20123 with Projections to 2035 dated June 2013, US Electric Power Monthly - September 2013 and Short-term Energy Outlook – September 2013. The U.S. 2012 calendar year energy sales are preliminary and 2013 are estimated.

RESIDENTIAL SECTOR

ENERGY SALES

Residential sector energy sales increased by 1.5% annually in fiscal year 2013 following an annual decrease in 2012 of 2.2%. Since the start of the economic downturn on the island in 2006, residential energy sales have dropped 8.2%. Over the past five fiscal years, 2008 – 2013, the CAGR of residential electrical energy sales was negative 0.3%. The Current Forecast projects that residential energy sales for fiscal year 2014 will increase by 2.4% and projects that over the next five fiscal years through 2018 the CAGR will increase by 1.5%.

The EIA reports the CAGR of residential sales in the U.S. decreased by 0.1% from 2007 – 2012. U.S. residential energy sales decreased 2.8% in calendar year 2012 and are estimated to decrease by 0.3% in calendar year 2013. The projected five-year compound growth rate in U.S. residential energy sales for calendar years 2013 through 2018 is 0.3%.

CLIENTS

The average number of residential clients from 2008 to 2013 increased at a CAGR of 0.6%, in spite of the reported overall decline in the island's population of more than 2% in that same timeframe. The average number of residential clients the Authority served during fiscal year 2013 was 1,353,550—an increase of 1.0% from the previous year. The Current Forecast projects that the average number of residential clients will increase by 1.1% in 2014 and continue to increase at a CAGR of 1.1% over the five-year period 2014 through 2018 as well.

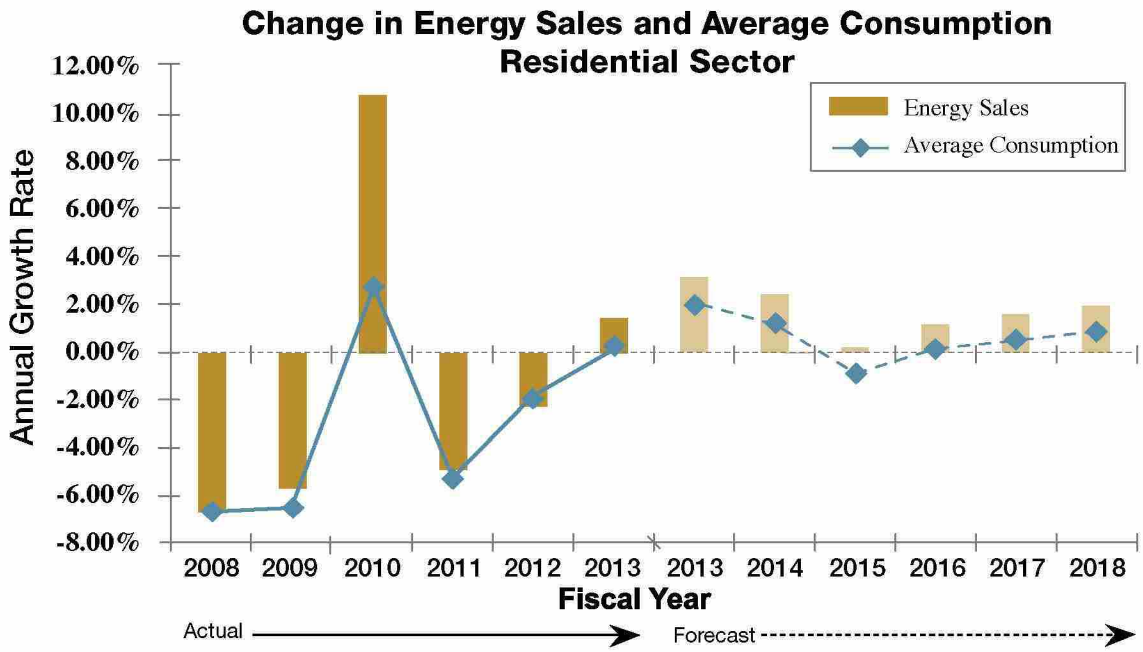
CONSUMPTION

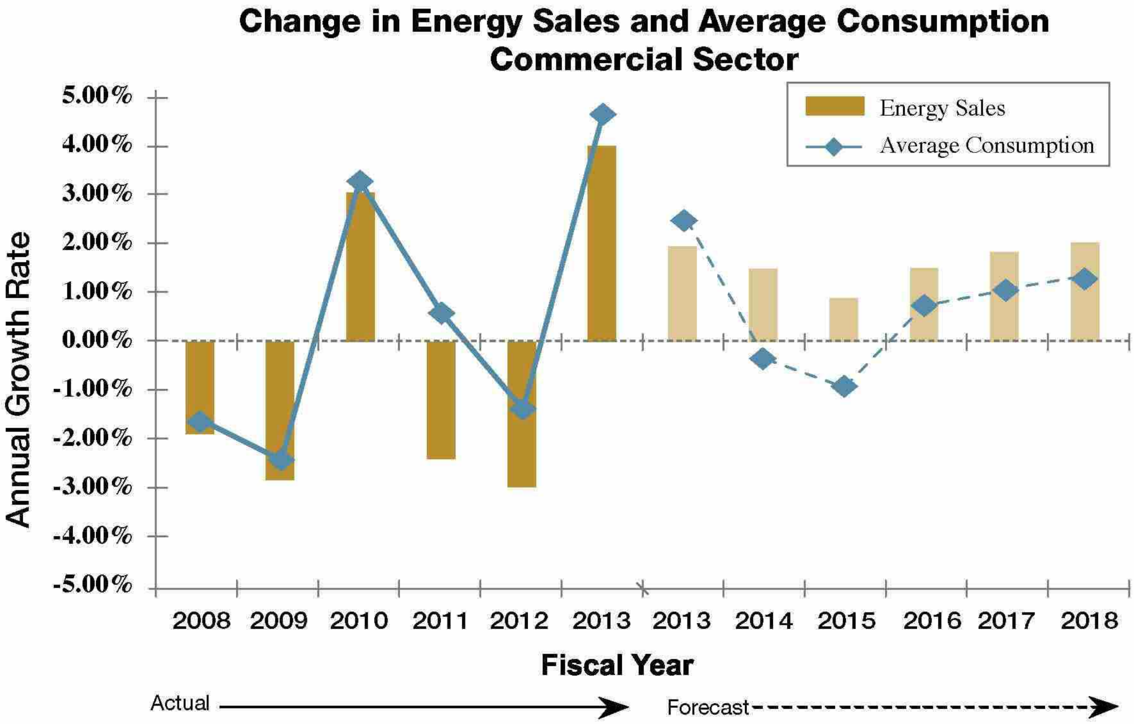
In fiscal year 2013 the average annual electric consumption per residential client was 4,917 kWh, which was 0.5% more than the previous fiscal year. In spite of the modest increase in the past year, over the previous five-year period the average consumption of the residential client decreased by a CAGR of 0.9%. In fiscal year 2014 the average residential energy consumption is forecast to increase by 1.3%. The Current Forecast projects that the residential sector consumption will increase at a five-year CAGR of 0.4% through fiscal year 2018. EIA data for recent performance of the U.S. electric sales are preliminary. According to EIA statistics, the average electric consumption of the Authority's residential clients is approximately 31% of the average electric consumption of residential clients of the U.S. East South Central Census Division which consists of the states of Alabama, Kentucky, Mississippi and Tennessee.

COMMERCIAL SECTOR

ENERGY SALES

Commercial energy sales for fiscal year 2013 increased 4.0% from the previous fiscal year. This level, however, was still 1.2% below the corresponding sales in fiscal year 2008. The Current Forecast projects that commer-





cial energy sales will increase 1.5% in fiscal year 2014 and increase at a five-year CAGR of 1.6% through 2018. In 2013 the government commercial classes consumed 32% of commercial energy sales.

Based on preliminary EIA data, U.S. commercial energy sales increased by 0.8% in calendar year 2012 and are estimated to decrease by 1.5% in calendar year 2013.

The preliminary five-year CAGR in U.S. commercial energy sales for calendar years 2007 through 2012 is negative 0.1%. The projected five-year CAGR in U.S. commercial energy sales for calendar years 2013 through 2018 is 0.7%.

CLIENTS

During fiscal year 2013 the average number of commercial clients was 126,735 which was a drop of 1.4% from the previous fiscal year. According to the Authority's June 2013 Governing Board Report, government and government agency clients made up 18% of the total commercial sector. Over the past five-years the CAGR in commercial clients was negative 0.5%. In fiscal year 2014 the average number of commercial clients is projected to increase by 1.9%, with continuous increase at a CAGR of 1.2% over the five year forecast period through fiscal year 2018.

CONSUMPTION

The average annual consumption per commercial client during fiscal year 2013 was 68,136 kWh for an increase of 5.6% over the previous year. In spite of last year's boost, the Authority's five-year CAGR in consumption per commercial client through fiscal year 2013 was a modest 0.3%. In fiscal year 2014 the average energy consumption per commercial client is projected to decrease 0.4%. The Current Forecast projects a CAGR of 0.4% in electric consumption per commercial client over the five fiscal years through 2018.

According to EIA statistics, the average energy consumption of the Authority's commercial clients is approximately 5.9% more than the commercial clients of the East South Central Census Division of the United States.

INDUSTRIAL SECTOR

ENERGY SALES

Industrial energy sales for the fiscal year 2013 decreased 7.2% compared to the previous year; more than the previous year's decline of 3.6%. This past fiscal year marked the seventh consecutive year that industrial energy sales have diminished. Following the client reclassification discussed below, between fiscal years of 2010 and 2013, industrial energy sales decreased by 15.4%.

During fiscal year 2009 the Authority reclassified 612 government industrial clients from the industrial General Service at Secondary Voltage tariff to commercial tariffs, to lower these clients' rates. The transfer of these clients from the industrial to commercial base reduced the size of the industrial sector by more than 40%, however, the transferred clients accounted for less than 10% of the industrial class's power consumption. Due to these changes the industrial sector

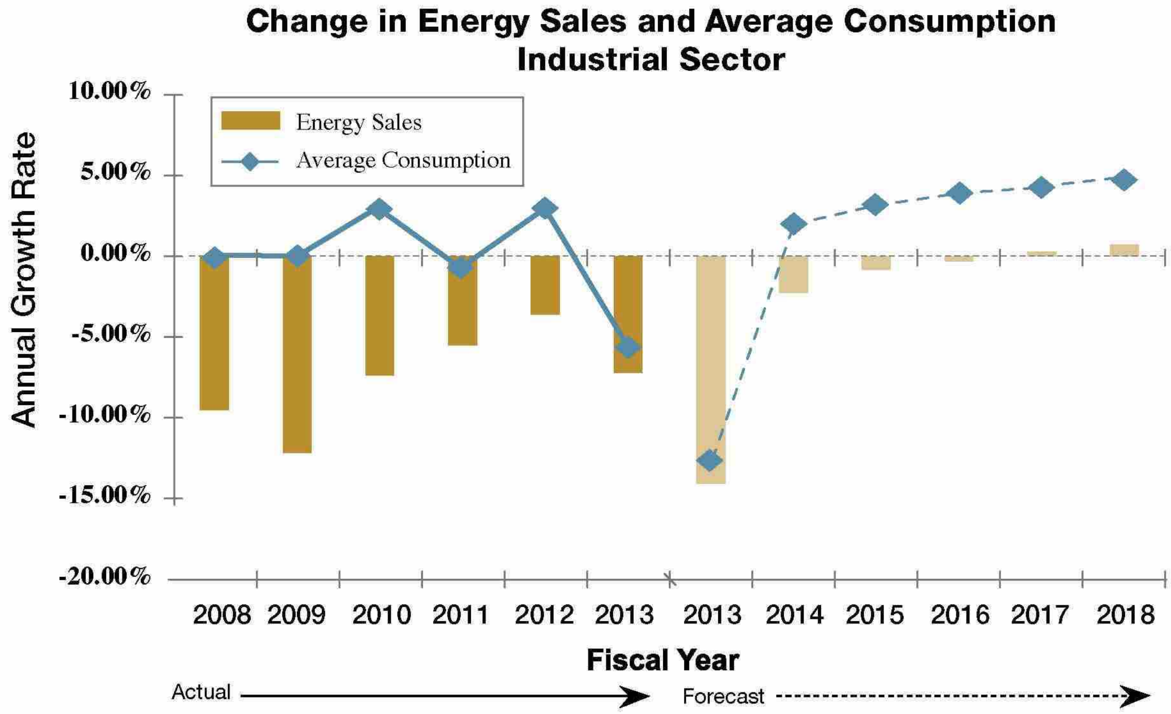


chart shows annual average consumption data starting in fiscal year 2010.

To develop the projection of industrial sector electric sales in the Current Forecast the Authority analyzes three groups: refineries and petrochemicals, customers with their own generation, and all the other clients; the last group represents more than 93% of the sector sales.

The smallest group within the industrial sector is the refineries and petrochemicals plants whose consumption in the past fiscal year was approximately 0.4% of the sector total. The electric consumption of refineries and petrochemicals was based on actual data for the first nine months of fiscal year 2013, with extrapolation for the balance of the fiscal year. The actual consumption totaled 9.3 million kWh, which was 19.7% less than the same period of the previous year.

The estimated electric usage of clients with their own generation facilities for fiscal year 2014 was based on data from fiscal year 2012 applied uniformly over the five years of the forecast. The total projected consumption by the three clients that own generation is 147.0 million kWh or 6.3% of the total industrial sales in fiscal year 2014. The impact of net-metering and wheeling tariffs were not considered in the intermediate term projection.

The Current Forecast projects that in fiscal year 2014 industrial energy sales will continue to decrease by 2.2%, followed by two more years of diminishing sales then reversing the negative trend in 2017 gradually hitting 0.6% in fiscal year 2018. The industrial sector energy sales are forecasted to decrease at a CAGR of 0.5% for the five-year period through fiscal year 2018.

Preliminary EIA data show total industrial U.S. energy sales increased 1.7% in calendar year 2012 and are estimated to decrease by 0.2% in calendar year 2013. The preliminary five-year CAGR in U.S. industrial energy sales for calendar years 2007 through 2012 is negative 0.7%. The projected CAGR in U.S. industrial energy sales for calendar years 2013 through 2018 is 2.6%.

CLIENTS

The average number of industrial clients served by the Authority at the end of fiscal year 2013 was 709, which was a modest drop from 733 in the previous fiscal year. Prior to the reclassification of more than 40% of the clients out of the sector in fiscal year 2009, the number of industrial sector clients had been declining. During the period of fiscal years 2009 through 2013 the number of industrial clients fell by 21%, or 189 clients. The Current Forecast projects the number of industrial clients will decrease by 28 clients in 2014 and continue to decrease by approximately 25 clients per year over the next four years, resulting in an equivalent CAGR of negative 4.0%.

CONSUMPTION

The average annual consumption of industrial clients during fiscal year 2013 was 3,636,652 MWh, a decrease of 4.1% from the previous year. The average industrial consumption for the period from 2010 through 2013 declined 3.6%. The Current Forecast

projects the average industrial client consumption will increase by 1.9% in 2014 and will increase at a five-year CAGR of 3.6% through fiscal year 2018.

According to EIA statistics, the average energy consumption of the Authority's industrial clients is approximately 62% less than those of the East South Central Census Division of the U.S.

OTHER CLASSES

The "Other" sector is comprised of clients in the public lighting, agricultural and other public authorities classes. In fiscal year 2013 energy sales in this sector represented approximately 1.9% of the Authority's total energy sales, a decrease of 25.8% from the previous year. Within this group public lighting represents approximately 76%, agricultural is 8% and public authorities 16%. The change in energy sales in fiscal year 2013 was basically due to the drop in consumption for public lighting down to historical levels. The total number of public lighting clients increased by 22% during the previous fiscal year, as the Authority installed more meters.

The Current Forecast projects no change in the number of clients in this group and only modest growth of 0.3% CAGR over the five-year forecast period ending in 2018.

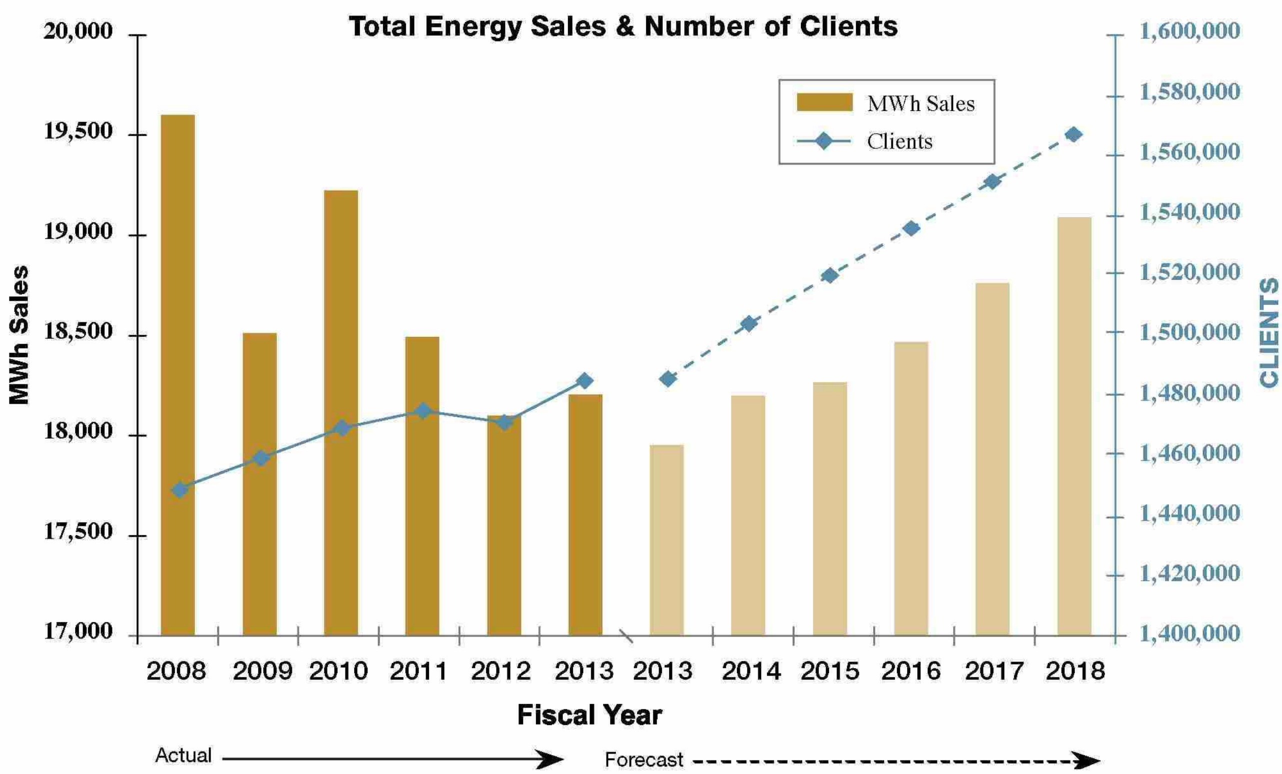
TOTAL ELECTRIC ENERGY SALES

Total reported energy sales in fiscal year 2013 were 18,221.2 GWh, an increase of 0.6% from those of the previous fiscal year. Total energy sales for the five-year period ended June 30, 2013 decreased at a CAGR of 1.5%. In the Current Forecast total energy sales are expected to increase by 1.3% for fiscal year 2014, and increase at a CAGR of 1.2% over the five-year period ending in fiscal year 2018.

The average number of clients that the Authority served during fiscal year 2013 increased by 0.8% to 1,485,150. Over the five-year period ending in fiscal year 2013 the CAGR in the number of clients was 0.2%. The total number of clients is projected to increase approximately 1.1% annually throughout the next five fiscal year forecast period ending in 2018.

The average electric consumption of the Authority's clients in fiscal year 2013 was 12,269 kWh, a decrease of 0.5% from the previous year. Over the past five-year period the CAGR of average consumption was negative 1.9%. The Current Forecast projects the average consumption of the Authority's clients will decrease in fiscal year 2014 by 0.1%, and the future five-year CAGR is projected to increase by 0.1% annually through fiscal year 2018.

The preliminary data for total U.S. energy sales show a decrease of 0.3% in calendar year 2012. For calendar year 2013 total energy sales in the U.S. are estimated to decrease by 0.6%. The CAGR for the U.S. preliminary total energy sales during the five-year period between calendar years 2007 and 2012 is negative 0.2% and is projected to be 1.1% for the five-year period ending in 2018.



RATES

Section 706 of the 1974 Agreement charges the Consulting Engineers to prepare each year a report setting forth their recommendations as to any necessary or advisable revisions of rates and charges

Section 502 of the 1974 Agreement details the Authority's responsibilities with respect to rates as follows:

> *The Authority further covenants that it will at all times fix, charge and collect reasonable rates and charges for the use of the services and facilities furnished by the System and that from time to time, and as often as it shall appear necessary, it will adjust such rates and charges so that the Revenues will at all times be sufficient.*

(B) after the outstanding 1947 Indenture Bonds have been paid or provision has been made for their payment and the release of the 1947 Indenture:

> *(a) to pay the Current Expenses of the System, and*
>
> *(b) to provide an amount at least equal to one hundred twenty per centum (120%) of the aggregate Principal and Interest Requirements for the next fiscal year on account of all the bonds then outstanding under this Agreement, reduced by any amount deposited to the credit of the Bond Service Account from the proceeds of bonds to pay interest to accrue thereon in such fiscal year.*

The revenues generated by the Authority's various rate schedules provide the moneys necessary for it to meet all of its obligations as detailed in the 1974 Agreement. Among its obligations are: paying the current expenses of the System; financing future growth by issuing Power Revenue Bonds; making deposits to specified funds; maintaining a minimum specified debt service ratio; and paying Contributions in Lieu of Taxes.

Typically, the client's bill consists of the appropriate base rate and an adjustment charge. The base rate encompasses current expenses, i.e. operation and maintenance (O & M) expenses (excluding the cost of fuel and purchased power), monies for funding requirements, Contributions in Lieu of Taxes associated with base rate revenue, depreciation and amortization, insurance, and debt service. The base rate has three components—a demand charge, a customer charge, and an energy charge, except for clients that receive electric service at secondary voltage. The base rate for clients served at secondary voltage is comprised of a customer charge and an energy-related charge. The adjustment charge has two components: the charge for purchased fuel and the charge for purchased power. (For a discussion of these charges see Adjustment Charge below.)

RATE SCHEDULES

CLASSIFICATIONS AND REVENUES

In order to serve different segments of its clientele, the Authority provides electric service in six client classifications. Ranking these classes in their order of revenue generated during fiscal year 2013, they are: Commercial, Residential, Industrial, Public Lighting, Public Authorities, and Agricultural. Three of these classifications—Commercial, Residential, and Industrial—represented 98.1 % of the kilowatt-hour sales and 97.2% of the revenues from the sale of electricity. The remaining three classifications – Public Lighting, Other Public Authorities, and Agricultural – collectively represented the balances of the Authority's kilowatt-hour sales and revenue from the sale of electricity.

Four rate schedules apply to the large majority of the Authority's client base. These four rate schedules are: GRS (General Residential Service), GSS (General Service at Secondary voltage), GSP (General Service at Primary voltage), and GST (General Service at Transmission voltage). These four rate schedules serve the majority of the Authority's clients because they were designed for wide applicability and they have few, if any, load characteristic requirements. To broaden their usage, the GSS, GSP, and GST rate schedules are available to both commercial and industrial clients. During fiscal year 2013 the core four rates accounted for 86.5% of the Authority's kilowatt-hour sales and 87.8% of its revenues from the sale of electricity.

The following table shows the major contribution of these four rate schedules to the Authority's electric sale and its total revenue. In each of the largest three classifications there is dominant rate schedule. For example, although four rate schedules apply to the Residential classification, the GRS rate schedule served 87.4 % of the Residential clients' kilowatt-hour sales and accounted for 90.0% of the Residential class revenue in fiscal year 2013. Within the Commercial classification seven rate schedules applied in fiscal year 2013, however, the GSP rate schedule, which served 8.1% of the Commercial clients, accounted for 53.4% of the Commercial class revenue. The GSS rate schedule generated the second most revenue in the Commercial classification; it served 91.4% of the Commercial clients and accounted for 28.4% of the Commercial class revenue. While thirteen rate schedules applied to the Industrial classification in fiscal year 2013, the GST rate schedule, which served 30.7% of the Industrial clients, accounted for 45.7% of the Industrial class revenue.

SUMMARY OF CORE RATE SCHEDULES ALL CLASSES

	Per Cent of Total MWH Sold	Per Cent of Total Revenue	Price Range* cents/kWh
General Residential Service	31.9%	31.1%	25.78
General Service Secondary Voltage	12.4%	14.3%	30.47 – 31.54
General Service Primary Voltage	26.0%	27.7%	28.25 – 28.63
General Service Transmission Voltage	16.2%	14.7%	24.22 – 23.87

* Commercial – Industrial Classes

The current rate schedules are comprised of more than 80 subcategories to accommodate various service levels and load profiles; the Authority presently serves all clients under 42 of the subcategories. Six of the rate schedules are common to both the commercial and the industrial classifications. Some of the rates serving few clients with low consumption are consolidated in the Rates Table presented in this report.

As shown on the Rates Table, the average cost per kWh for all power sold by the Authority was 26.46 cents during fiscal year 2013. The lowest average cost among the four popular rate schedules was 23.87 cents/kWh for GST - Industrial, with the highest average cost being 30.47 cents/kWh for GSS - Industrial.

RATES TABLE

Rate Schedule	Average Number of Clients	Total MWh	Total Revenue ($000)[1]	Average Cost Cents/kWh[2]
Residential Class[3]				
103-104 (RH-3)	7,624	21,763	5,291	24.31
105-107 (RH-3) Revised	40,194	247,174	20,432	8.27
109,110 (LRS)	162,459	566,651	140,998	24.88
111,112 (GRS)	1,143,273	5,820,008	1,500,420	25.78
Total Residential Class	*1,353,550*	*6,655,596*	*1,667,141*	*25.05*
Commercial Class				
060 Telephone Booth	59	10	3	32.35
070-080 Cable TV	17	13,730	4,111	29.94
082 Security Cameras	166	96	38	39.58
211 (GSS)	115,866	2,252,521	686,272	30.47
212 (GSP)	10,270	4,567,496	1,290,545	28.25
213 (GST)	357	1,793,680	434,508	24.22
862	1	7,632	2,004	26.26
Total Commercial Class	*126,735*	*8,635,165*	*2,417,481*	*28.00*
Industrial Class				
311 (GSS)	135	4,841	1,527	31.54
312 (GSP)	304	164,060	46,973	28.63
313 (GST)	217	1,152,052	274,941	23.87
333 (LIS)	2	214,301	47,024	21.94
343 (PPBB)	2	1,157	1,865	161.24
363 (TOU-T)	13	422,922	96,843	22.90
393 (SBS-T-TOU)	1	40,963	9,989	24.39
603 (SR-GST)	20	300,158	62,070	20.68
613 (SR-GST)	5	67,939	15,016	22.10
623 (SR-TOU-T)	1	13,202	2,675	20.26
653 (SR-TOU-T)	5	93,096	20,860	22.41
753 (SRTOU-T)	2	70,817	15,461	21.83
963 (TOU-T)	2	32,879	7,014	21.33
Total Industrial Class	*709*	*2,578,386*	*602,263*	*23.36*

Rate Schedule	Average Number of Clients	Total MWh	Total Revenue ($000)[1]	Average Cost Cents/kWh[2]
Other Classifications				
Public Lighting				
2-41 (Non Meter P/L)	877	235,313	104,274	44.31
72 (PLG Bus Shelter)	3	435	127	29.20
73 (PLG Police)	5	33	8	25.26
414 (LP-13)	10	3,065	984	32.11
421 (PLG)	103	1,926	596	30.94
422 (PLG)	78	1,319	362	27.44
423 (PLG)	712	4,146	1,176	28.35
424 (PLG)	1,138	19,163	5,283	27.57
050-056 (Dusk to Dawn)	0	2,922	726	24.85
Total Public Lighting	*2,926*	*268,322*	*113,537*	*42.31*
Agricultural				
711 (GAS)	1,227	27,277	7,585	27.81
Total Agricultural	*1,227*	*27,277*	*7,585*	*27.81*
Public Authorities				
513 (GST-Public Authority)	3	56,436	13,342	23.64
Total Public Authorities	*3*	*56,436*	*13,342*	*23.64*
Total Other[4] Classifications	*4,156*	*352,035*	*134,463*	*38.20*
Total	*1,485,150*	*18,221,182*	*4,821,348*	*26.46*

[1] Includes the Adjustment Charge.
[2] Calculated differences are due to rounding.
[3] Includes the residential fuel subsidy.
[4] Includes Public Lighting, Agricultural and Public Authorities classes.

The Authority's ten largest non-governmental agency industrial clients accounted for 27.2 % of the classification's consumption and paid an average of 22.55 cents/kWh during fiscal year 2013. This was 3.5% less than the industrial class average.

The Rates Table shows all the rate schedules in use during fiscal year 2013 by the Authority's clients, with the average number of clients, total annual power sales, total revenue and average pricing for each rate schedule.

RATE STABILIZATION FUND

Beginning in December 2011 the Authority implemented a temporary program to provide a measure of rate relief to General Residential Service (GRS) clients who were current in their payments, consumed more than 425 kWh per month, and did not otherwise receive any other subsidy. This Rate Stabilization Fund was funded as part of a line of credit from the Government Development Bank (GDB) and was directed to reducing the monthly fuel adjustment charges to maintain parity with the fuel charges from September 2011. The program was revised late in May 2012, with the same general objective; the new fuel stabilization program was established for 180 days.

During fiscal year 2013 the Authority used the Rate Stabilization program to subsidize a total of $53.2 million in residential client fuel adjustment credits.

RATE STRUCTURE

Prior to October 1999 the Authority's electric service rates consisted primarily of a base charge and a fuel adjustment charge. During that period the base charge included a fuel charge of $2.00 per barrel. The fuel adjustment charge recovered the Authority's fuel-related costs in excess of the $2.00 in the base charge. For clients served at secondary voltage (such as the entire residential class) the base rate included a demand component, whereas for clients served at primary and transmission voltages the demand charge was a separate component of the bill.

The fuel adjustment clause was revised by the Authority in November 1999 to recover the cost of purchasing power from EcoEléctrica, a cogeneration plant, during its test and start-up period. On March 28, 2000, following the required public hearing, a permanent revision of the Authority's rate structure was approved that incorporated a purchased power charge in the electric service rates to recover its cost of purchased power from the EcoEléctrica plant. Since then the purchased power charge has been applicable for purchases from EcoEléctrica and, subsequently the second cogenerator, AES-PR; the purchased power charge also applies to the renewable power sources that began to come on-line during the past fiscal year. The rate structure revision also removed the $2.00 per barrel fuel charge from the base charge and included all fuel related charges in the newly defined adjustment charge. The fuel charge and the purchased power charge, both of which became effective June 5, 2000, are collectively shown on the client's bill as the adjustment charge.

In May 2013 the Authority implemented revisions to recover the costs of renewable energy credits associated with the purchased renewable energy. At the same time the Authority revised the fuel adjustment to explicitly include natural gas.

The base rates and demand charges were not revised with the adjustment charge discussed above and have remained unchanged since they were established in 1989.

The Authority invoiced $3,707.3 million through the adjustment charge in fiscal year 2013: $2,862.0 million for fuel and $845.3 million for purchased power. The adjustment charge constituted 76.9 % of the Authority's $4,821.3 million in electric revenue.

PRICE COMPARISONS

The Authority's average price per kilowatt-hour varies significantly among its client classifications. The Power Producers' at Bus Bar Rate paid the highest average cost of 161.24 cents/kWh, which reflects the recurring high demand charges relative to infrequent consumption; the average cost for this service was 55.97 cents/kWh during the previous fiscal year. The most expensive widely used rate was Commercial General Service at Secondary voltage, with an average of 30.47 cents/hWh. The lowest cost service was the Residential Public Housing Rate - Revised with the average cost of 8.27 cents/kWh. These price variations are attributable to the differences in the cost of providing public service and socioeconomic objectives of the Commonwealth government and the Authority.

The average prices in cents/kWh for the Authority, Hawaii, and the U.S. are shown in the following table for the year ended June 30, 2013. The data for the State of Hawaii are provided because its geographical characteristics and fuel mix are similar to Puerto Rico's. The U.S. Department of Energy - Energy Information Administration (EIA) data were used as a reference to derive the pricing for the State of Hawaii and the U.S. The U.S. data are comprised of all fifty states and Washington D.C.

2013 AVERAGE PRICE COMPARISON
(Cents/kWh)

	Authority	Hawaii	U.S.
Residential	25.05	33.87	11.97
Commercial	28.00	32.30	10.19
Industrial	23.36	28.21	6.78
All Classes	23.46	31.20	9.98

SUBSIDIES AND CREDITS

In accordance with various Commonwealth laws and regulations, the Authority provides subsidies to low consumption residential clients, energy conserving hotels, charitable organizations, agricultural clients, low-income clients with life sustaining equipment and small water companies distributing potable water.

The Authority's subsidies and credits benefited an average of 484,227 clients in fiscal year 2013, which is approximately 33% of its client base. The total cost to the Authority for the benefits credited to these clients during fiscal year 2013 was $80.0 million. The participation rate and cost to the Authority were unchanged from the previous fiscal year. Funds for these subsidies were drawn from the Set Aside moneys discussed in the *Contributions in Lieu of Taxes and Other* section in the *Financial* section.

RESIDENTIAL FUEL SUBSIDY

Under provisions of Act No. 106 of the Legislature of Puerto Rico, approved on June 28, 1974, the Commonwealth began to subsidize the fuel adjustment charge (now the fuel charge, a component of the adjustment charge). In 1991 the subsidy qualification criteria were made more restrictive, to focus the subsidy on those clients truly in need. The new criteria are still in place and apply to the Authority's residential clients who consume up to 425 kilowatt-hours of electricity monthly or 850 kilowatt-hours bimonthly and meet the following criteria: those on the "Lifeline" residential rate (LRS), the government-administered public housing rate (RH-3), full-time students, the handicapped, and those 65 years of age or older. Additionally, all fuel subsidy recipients must be permanent residents of the Commonwealth of Puerto Rico and may receive the subsidy on only one dwelling. The subsidy is provided in the form of a credit against the recipient's electric bill. During fiscal year 2013, there were an average of 302,771 clients or 22% of the total residential classification who qualified for subsidization. The purchased power component of the adjustment charge is not subsidized.

The residential fuel subsidy was $26.4 million during fiscal year 2013, which represented a 9.6% decrease over the previous fiscal year's level. The Commonwealth's contribution to the fuel charge subsidy program is deducted from the electric energy sales Set Aside. (See *Contributions in Lieu of Taxes and Other* section).

Until fiscal year 1992, the residential fuel subsidy was paid by the Commonwealth and was recorded as a receivable by the Authority. By the end of fiscal year 1991, the Commonwealth owed the Authority $94.9 million for the fuel charge subsidy program. In October 1991, the Authority and the Commonwealth entered into a non-interest bearing, fifteen-year payment plan for payment of this past due amount. In June 2004, the Legislature of the Commonwealth of Puerto Rico superseded the 1991 agreement with a revised agreement containing an eight-year payment schedule that totaled $55.7 million. This amount includes an allocation for past due Commonwealth government account receivables and the unpaid balance of the fuel adjustment subsidy. The Commonwealth made its final payment to the Authority of $6.3 million in fiscal year 2013.

The Authority pays the entire fuel subsidy for all residential rate classifications until the price of oil reaches $18.00 per barrel. Once the price of oil exceeds $18.00 per barrel, the Commonwealth pays (by means of the electric energy sales Set Aside) the incremental price until it reaches $30.00 per barrel. This subsidy amount is capped at $100 million per year. The client pays the incremental amount over $30. For the other recipients of the residential fuel subsidy, the Commonwealth pays (once again, by means of the electric energy sales Set Aside) the entire subsidy up to $30.00 per barrel. The Authority's monthly average cost of fuel in fiscal year 2013 ranged from a low of $105.69 per barrel in November 2012 to a high of $120.51 per barrel in February 2013. The weighted average fuel cost for the fiscal year 2013 was $111.18 per barrel, which is down over 6% from the previous year.

The residential fuel subsidy applies to the fuel adjustment charge for service at secondary voltage. The subsidy for qualifying residential clients is a sliding scale percentage that corresponds to their monthly consumption level. As shown on the table below, the subsidy percentage decreases as monthly consumption increases. The subsidy is not cumulative through the incremental blocks of consumption; for example, a client with a monthly consumption of 325 kWh would receive a 55% subsidy of the fuel adjustment charge. There is no subsidy if the monthly consumption exceeds 425 kWh.

Monthly Consumption (kWh)	% of Total Fuel Component Subsidized
0-100	90
101-200	75
201-300	65
301-400	55
401-425	*
Over 425	0

*For the first 400 kWh of consumption, 55% of the fuel charge will be subsidized; over 400 kWh the client will be charged 100% of the fuel charge for each additional kilowatt-hour up to 25 kWh.

RESIDENTIAL RATE SUBSIDY

The Authority serves its residential clients using four rates—GRS, LRS (Lifeline), and RH-3 (Public Housing) and a revised RH-3 rate. In fiscal year 2013, 84.5% of its residential clients were served using the GRS rate. The remaining residential clients were served using the LRS and RH-3 rates that are reserved for those who qualify as low-income; these rates have lower customer and energy charge components as compared to the GRS Rate.

During fiscal year 2013 the Authority served on average 210,277 residential clients under the rates of LRS, RH-3, and RH-3 Revised, which is discussed in Selected Rates. In the past fiscal year an average of 165,726 clients or about 12% of the residential clients received the base rate subsidy at a cost to the Authority of $15.6 million, little changed from the $15.4 million subsidy in fiscal year 2012..

HOTEL SUBSIDY PROGRAM

Under Act No. 101 of July 9, 1985, the Authority started providing an 11% discount on its monthly electric bills to hotels that are certified by the Puerto Rico Tourism Company. This subsidy is designed to help conserve energy and promote tourism. In order to qualify for this discount the hotels are obligated to: develop programs for conserving and using energy more efficiently; submit evidence annually to the Commonwealth's Energy Affairs Administration, which administers the program, showing that they are implementing their programs; and remain current in paying their electric bills. Small hotels are only required to demonstrate compliance every five years. If a participating hotel does not pay its bill within 60 days, the hotel can be dropped from the program.

Act No. 266 of November 16, 2002, amended several articles of Act No. 101. The most notable change was the reduction in the number of rooms required to qualify for the discount from fifteen to only two. This subsidy, like the residential fuel subsidy, takes the form of a credit on the client's bill. During fiscal year 2013, an average of 210 establishments benefited from the $8.9 million in hotel subsidies.

CHARITABLE ORGANIZATIONS SUBSIDY

This subsidy applies to charitable organizations, such as churches, which provide services to the community at no charge. The subsidy enables any qualifying charitable organization to use the GRS rate (average cost of 25.78 cents/kWh during fiscal year 2013) in place of the other applicable commercial rates (30.47 cents/kWh for GSS or 28.25 for GSP). Applying the GRS rate in place of the GSS rate reduced the client cost by almost 15% in fiscal year 2013, while the GRS rate in place of the GSP rate saved 9%.

The Authority subsidized $4.7 million to serve an average of 4,390 charitable organizations in fiscal year 2013.

LIFE PRESERVATION SUBSIDY

The Life Preservation subsidy is available to qualifying low-income clients who require electrically powered essential medical equipment. The subsidy provides full credit for the electrical consumption of the medical device, based on the certification of need and hours of operation established by a physician from the Department of Health of Puerto Rico.

This subsidy served approximately 4,800 clients and amounted to $4.6 million in fiscal year 2013, a decrease from the $5.1 million cost in the previous fiscal year.

AGRICULTURAL SUBSIDY

The Agricultural service rate (GAS) is available to farmers, animal breeders and rural irrigation water suppliers. This rate is available for the clients whose load is up to 50 kVA. If the Authority did not provide the GAS rate to these clients they would be served under the more expensive GSS-Commercial rate. In fiscal year 2013 the average price differential between the GSS-Commercial and GAS rates provided approximately a 9% reduction in costs to qualified clients.

This subsidy served an average of 1,278 clients, with their cost savings totaling $549,600 in fiscal year 2013.

IRRIGATION SERVICE SUBSIDY

The Authority originally was constituted as the Puerto Rico Water Resource Authority which generated power from hydro-electric facilities. It included dams and infrastructure that also provided most of the island's water. The Authority still maintains jurisdiction over all dams on the island, however the Puerto Rico Aqueducts and Sewers Authority (PRASA) is the current public agency that is responsible for the water system on the island.

As part of its legacy responsibilities the Authority provides certain technical and maintenance services for dams that supply PRASA and some irrigation users. During fiscal year 2013 the Authority incurred costs of $5.6 million for these services.

COMMON AREA LIGHTING SUBSIDY

Act 1060 passed by the Commonwealth's legislature in August 2008 established that lighting for common areas of condominiums will be served under a rate based on general service residential (GRS). In fiscal year 2013 the average cost savings per kWh was almost 15% and totaled $1.3 million for condominium common area lighting.

OTHER SUBSIDIES AND CREDITS

The manufacturing industrial credit is provided to all new manufacturing industry clients and to the clients who expand their business operation. During fiscal year 2013, the Authority provided its manufacturing industry users a credit of $10.8 million to an average of 28 clients; the credit amounted to an increase of approximately 7% over the previous fiscal year. This credit is discussed below in Special Rates.

As discussed in the *Contributions to the Commonwealth* section, the Economic Incentives Act of 2008 requires the Authority to provide certain energy credits for qualifying businesses; the costs of the energy credits are shared between the Commonwealth and the Authority and are applied to the qualifying business's income taxes. During the ten year term of the legislation the Authority's share steadily increases from zero to 80% of the credit. In fiscal year 2013 the Authority's costs associated with this legislation were $1.2 million, based on tax credits for seven qualifying businesses.

In 2004 a subsidy was established for cooperative water companies that provide potable water to rural communities which were either not served or inadequately served by PRASA. In order to qualify for the subsidy, the rural water company must be registered with the Commonwealth, its operation must meet Commonwealth health standards and the water quality must comply with US EPA criteria. During fiscal year 2013 an average of 14 rural water companies took advantage of this subsidy and received a benefit of approximately $3,900.

Since July 2, 2007, the Authority has allowed a 10% credit on its residential clients' basic rate charge for those clients who are current in their payments and pay the Authority directly from their personal bank account. In fiscal year 2013 approximately 3,900 residential clients took advantage of this credit and saved almost $128,400.

The Authority provides a 10% credit for power, up to a maximum of $40 per month, to small commercial clients with less than seven employees on the weekly payroll. This credit applies for up to three years. During fiscal year 2013 the credit provided was approximately $1,790 to six clients.

SELECTED RATES

Over the last decade the Authority has developed a number of specialized rates to address certain pricing and operational issues for some of its residential public housing, large commercial and industrial clients. By design, these rates have limited applications. The commercial and industrial rates are almost exclusively available to clients purchasing power at the transmission level.

PUBLIC HOUSING RESIDENTIAL RATE

As shown in the Rates Table, approximately 3.5% of the Authority's residential clients are served by the RH-3 public housing rate. In August 2009 the Commonwealth enacted legislation, under Act No. 69, entitled Special Law for Pricing Justice of Utilities for Public Residents. The Special Law provides simplified low cost water and electric utility rates for qualifying low income residents of public housing. The new electric rates went into effect in February 2010, under the scope of RH-3 Revised. The rate structure establishes flat monthly charges based on the number of rooms: $30 for one room, $40 for two or three rooms, and $50 for four or five rooms. The rate applies for usage up to 425 kWh per month. For a client to transition from RH-3 to the RH-3 Revised tariffs there must be an agreed payment plan if there are any overdue invoices. By the end of fiscal year 2013, over 84% of the total RH-3 clients had opted for the RH-3 Revised rate. During the last fiscal year the clients served under the RH-3 Revised rate consumed approximately 92% of the total RH-3 power and contributed approximately 79% of the total RH-3 revenue.

SPECIAL RATES

In order to promote an increase in industrial development in Puerto Rico, the Authority instituted five new special rates. These special rates offered a discount for new industries and expansion of existing industrials on or after February 2002. New industrial clients received a discount of approximately 11% on their total electric bill. Also, existing industrial clients that expanded their operations received a discount of approximately 11% on the demand, energy, and adjustment charges associated with its expansion. These rates were available for five years effective July 30, 2003. While these rates expired on July 30, 2008, they are available to existing users to complete the

balance of their five year term. During fiscal year 2013 these rates benefited qualifying industrial clients with savings of $14.3 million; the savings were $18.8 million in fiscal year 2012. The five special rates are designated as follows:

- General Service at Transmission Voltage-Special (SR-GST)
- Time of Use Rate at Transmission Voltage-Special (SR-TOU-T)
- Large Industrial Service 115 kV-Special (SR-LIS)
- Standby Service at Transmission Voltage-Special (SR-SBS) and
- Time of Use Rate-Cool Storage Air Conditioning Systems-Special (SR-TOU-C)

Only three of these rates —SR-GST, SR-TOU-T, and SR-SBS-TOU-T— were used during fiscal year 2013. The SR-GST rate was used by 25 clients with a combined average cost of 20.94 cents/kWh. The SR-TOU-T Rate served six clients at a combined average cost of 22.14 cents/kWh; the SR-SBS-TOU-T Rate served two clients with an average cost of 21.83 cents/kWh..

LARGE INDUSTRIAL SERVICE RATE

In September 1997, the Authority adopted the Large Industrial Service (LIS) rate in order to encourage large industrial clients to remain part of its client base. To be eligible for this rate clients must meet the following criteria: receive service at 115 kV; have a demand of 12,000 kW or greater; a minimum load factor of 50% (see following discussion); and an average monthly power factor of 95% or more. In view of the declining industrial client base, the Authority has relaxed the previously required 80% load factor to 50% for LIS and SR-LIS through January 2016. The 50% load factor, however, is then the minimum basis for monthly billing. The Authority has served two industrial clients under the LIS rate for the past three fiscal years, up from only one client in fiscal year 2010. The average cost per kWh for this rate was 21.94 cents/kWh in fiscal year 2013, up approximately 2% over the previous fiscal year.

TIME-OF-USE RATES

Time-of-Use (TOU) rates are a component of the Authority's Demand-Side Management (DSM) program. (For a discussion on the DSM program refer to the *Demand and Energy Forecast* section.) These rates are designed to encourage shifting consumption from on-peak hours to off-peak hours when the total system demand is otherwise lower. The Authority has several TOU rates; currently these rates are only offered to the Authority's commercial and industrial clients.

In May 1996, the Authority's Governing Board adopted Resolution Number 2160, which approved revised load requirements, thereby increasing the number of clients eligible for TOU rates. At the end of fiscal year 2013, a total of 24 clients were served under these rates, resulting in $152.8 million in revenues, which was approximately 25% of the total industrial classification's revenue. One of these clients was served under the SBS-T-TOU (standby service at transmission voltage) rate discussed below.

The average cost for all the TOU rates in fiscal year 2013 was 22.68 cents/kWh, however, the costs for separate rates varied considerably based on the pattern of client utilization and load characteristics. Amongst this group of rates the most frequently used was the TOU-T (time of use at transmission voltage) rate which accounted for more than 63% of the TOU revenues. Thirteen clients were served using the TOU-T rate at an average cost of 22.90 cents/kWh. The second largest energy sales and revenues of this group was the standby service rate discussed below, it provided almost 15% of the TOU revenue.

The remaining TOU rates accounted for 21% of the energy sales and revenues for this group. Six clients were served under SR-TOU-T rates. The SR-TOU-T Rates are available under Special Rates to manufacturing clients who are either new or have added to their electric load during the past fiscal year. The last TOU rate utilized in fiscal year 2013 was the TOU-T rate, which applies to industrial clients who have a load demand of 1,000 KVA to 3,000 KVA. During fiscal year 2013 this TOU-T rate served two clients at an average cost of 21.33 cents/kWh.

Another available TOU rate is the Cool Storage Air Conditioning Systems (TOU-A/C) commercial rate. Although this rate has been in existence for almost two decades, it attracted few clients and the last one changed to a conventional rate several years ago.

STANDBY SERVICE RATE

The Standby Service Rate (SBS) is applicable to industrial or commercial clients who generate power for their own use and not for resale. This rate schedule provides four levels of service: supplementary, auxiliary, maintenance, and interruptible power. When the client's generator is unable to generate enough power needed to satisfy its load, whether because of a limitation or a scheduled or forced outage, then the client starts to receive its needed power automatically from the Authority. The demand, customer, and energy-related costs for this rate are the same as those in the corresponding service class that would apply, namely GSP, GST, TOU-P, or TOU-T rates.

During fiscal year 2013 there was only one standby rate in use. It served one industrial client utilizing the SBS-T-TOU rate, discussed above. The average cost of the SBS rate for this industrial client was 24.39 cents/kWh. The Authority received $10.0 million in revenue from the sale of 40,963 MWh under this rate.

POWER PRODUCERS AT BUS BAR RATE

In March 2000, the Authority's Governing Board, under Resolution Number 2812 approved the Power Producers at Bus Bar (PPBB) rate. This rate, which became effective in June 2000, is only available to large power producers who are connected at 230 kV and have a power purchase agreement with the Authority for all its electrical output. In addition, the power producer must have at least an 85% equivalent availability. Under this rate a power producer can purchase power from the Authority for startup, scheduled maintenance, and for backup power.

Presently, only EcoEléctrica and AES-PR qualify for this rate. The black-start energy requirements for these two power producers are 12.0 MW and 38.7 MW, respectively. The Authority generated approximately $1.9 million in revenues from the sale of 1,157 MWh of power to the two cogenerators in fiscal year 2013. The average cost for this rate was 161.24 cents/kWh during the past fiscal year.

SECURITY CAMERAS RATE

As part of an increased public safety program throughout the Commonwealth, security camera surveillance systems and wireless telecommunication equipment have been installed on the Authority's poles and structures.

The Authority instituted a temporary rate for unmetered small load service (USSL) in July 2007 and subsequently added this new rate in its rate structure in January 2008. The rate is applicable to all security cameras and communication equipment installed on the Authority's electric poles anywhere on the island. Before installation of these security devices, the client is required to provide all equipment specifications to the Authority's Director of Transmission and Distribution. The electric consumption for each installed security camera may not exceed 200 kWh per month.

During fiscal year 2013 an average of 166 clients used this rate. The average monthly consumption was 48 kWh per client, which was less than one-half the average consumption in the previous fiscal year. Their average cost was 39.58 cents per kWh for fiscal year 2013.

COST OF SERVICE

A cost of service study is an analytical tool that determines the proper allocation of capital investment and expenses associated with providing electric power to various clients. The results of the studies are used when designing various rate schedules.

The Authority's most recent cost of service study was performed using data from fiscal year 2011. This study employed methodologies that are commonly accepted in the electric utility industry. The study results included the allocation of costs and revenues, as well as an analysis based on rate base and its rate of return

The revenues, expenses and recovered cost percentage from the cost of service study based on fiscal year 2011 for the major classes of service are tabulated :

COST OF SERVICE RESULTS BASED ON 2011 DATA
($ millions)

Rate Schedule/Class	Revenues	Cost to Serve	Recovered Cost Percentage
Residential	1,586.4	1,851.9	85.7
Commercial	2,115.4	2,050.6	103.2
Industrial	598.7	590.6	101.4
Other Classes	125.1	201.9	62.0

It should be noted that the results of a Cost of Service study are not the only criteria used to design rates. The Authority uses other important criteria including socioeconomic, energy conservation, and load management objectives.

CONSULTING ENGINEERS RECOMMENDATION

The 1974 Agreement stipulates that after payment of all current expenses, the remaining net revenue must equal or exceed 120 per centum of outstanding debt service. The Consulting Engineers monitors on an ongoing basis that the Authority's rate schedules will generate sufficient revenues to pay its current expenses and have adequate debt service coverage. The Authority's debt service coverage ratio for fiscal year 2013 was 1.38. The debt service coverage for fiscal year 2014 is forecasted to be 141% based on the Authority's Annual Budget discussed in the *Financial* section.

FINANCIAL

The financial data used in this Annual Report are based on statements in the Authority's Audited Financial Statements and on information provided by the Authority. The Authority's Audited Financial Statements prepared by the Authority's Auditors for fiscal year 2013 includes Schedules II through VI, which present certain information in accordance with the 1974 Agreement, including a reconciliation of Net Revenues under generally accepted accounting principles with the 1974 Agreement. The primary differences are Net Revenues under the 1974 Agreement excludes depreciation expense, other post-employment benefits and payment on Power Revenue Bonds debt service. The financial data in the Annual Report are based on accrual basis accounting.

ANNUAL BUDGET

The Annual Budget, prepared in conformance with Section 504 of the Trust Agreement, consists of four statements and two exhibits. The four Statements are: a pro forma income statement for the ensuing fiscal year; a projection of capital expenditures also for the ensuing fiscal year; a summary of capital expenditures and the sources of construction funds to support the expenditures; and a schedule of funds to be provided by the Government Development Bank for Puerto Rico (GDB). The two exhibits are a five-year projection of debt service and Contractual Obligations and Contributions in Lieu of Taxes and Other. The Annual Budget for fiscal year 2013 that is referenced in this report was prepared by the Authority during the last quarter of fiscal year 2012.

The Proposed Annual Budget of Current Expenses and Capital Expenditures – Fiscal Year 2013-2014 was approved by the Consulting Engineers and adopted by the Governing Board in May 2013.

REVENUES

Total revenues booked for fiscal year 2013 were $4,850,816,378 or 4.0% less than the previous years' actual results, but within 0.2% of the forecasted revenues. The decreased revenues were primarily the result of lower fuel costs and therefore lower fuel adjustment charges. Total revenues for fiscal year 2014 are forecasted to be $4,494,211,000 or an annual decrease of 7.4%. The Authority's projected revenues for the five-year intermediate forecast include $30 million each year for billings of power lost to theft as a result of the significant initiative to recover these losses. For fiscal years 2015 through 2018 total revenues are forecasted to be $4,558,037,000, $4,538,771,000, $4,589,252,000, and $4,519,866,000, respectively. The Authority's income statements (including interest income) for fiscal years 2013 through 2018 are presented in *Appendix II, Income Statement*. Revenues from electric sales are shown on *Appendix I, Intermediate-term Financial Planning Forecast* which breaks down the revenues by sector and the three components that the revenue is based on—the base revenue, the fuel adjustment charge and the purchase power adjustment charge—for the six year period 2013 through 2018.

As shown on *Appendix I,* base revenues from sales of electricity for fiscal year 2013, excluding fuel and purchased power costs that are included in the adjustment charge, were $1,114,052,000 and are forecasted to be $1,109,790,000 for fiscal year 2014 or a decrease of 0.4%. The base revenue projections move with the forecasted energy sales for fiscal years 2015 through 2018, shown in the first category of the appendix as kWh sales.

As discussed in the *Rates* section the Authority had a temporary rate stabilization program in effect during the first five months of fiscal year 2013. The program effectively subsidized certain residential clients for $53.2 million. The reported revenues for the residential sector reflect this 3.2% reduction.

EXPENSES

The Authority's budget for Current Expenses for fiscal year 2013 and the amounts actually expended, as well as those budgeted for fiscal year 2014, are tabulated for reference. Expenses incurred during fiscal 2013 were more than those budgeted by 2.1%. Extracting fuel and purchased power the variance was 10.7% more than that budgeted.

The current expenses for fiscal year 2014 are forecast to be 10.3% less than actual expenses in fiscal year 2013. The projected reduction in current expenses in fiscal year 2014 is based primarily on the cost of fuel projected to decrease by 17.6% and a 2.3% drop in the budget for other current expenses, except purchased power, which is projected to increase by 6.6%. Over the five-year intermediate forecast current expenses other than fuel and purchased power are projected to decrease by 2.4% in 2015, then increase by 1.1% in 2016, increase 0.3% in 2017 and be unchanged in 2018.

OPERATING AND MAINTENANCE EXPENSES

In fiscal year 2013, total Operating and Maintenance (O&M) expenses were $4,125,390,000 and for fiscal years 2014 through 2018 are forecasted to be $3,700,008,000, $3,734,895,000, $3,716,576,000, $3,749,204,000 and $3,671,427,000. *Appendix III, Detail of Operating and Maintenance Expenses,*

shows O&M expenses by category for fiscal years 2013 through 2018.

The cost of fuel is the largest component of O&M expenses. During fiscal year 2013 approximately 65% of the System's energy was generated by the Authority's fossil fuel plants, with a total fuel cost of $2,603.6 million; this constituted 63.1% of the total O&M expenses for the year. The total cost of fuel for fiscal year 2014 is forecasted to be 17.6% less than the actual costs in fiscal year 2013, driven by forecasted near term decreases in oil prices and the increased use of natural gas at the Authority's Costa Sur steam plant. The costs of fuel in fiscal year 2013 and the forecasted costs during fiscal years 2014 through 2018, including the type of fuel, are discussed in the *Capacity and Energy Resource Planning* section above. In addition, *Appendix IV, Annual Net Generation, Fuel Consumption, Fuel and Purchased Power Costs,* shows the cost of fuel and the generating efficiency (kWh generated per barrel) for each major generating facility. Actual data are shown for fiscal year 2013 and forecast data through 2018.

In reference to *Appendix III, Detail of Operating and Maintenance Expenses,* the forecasted breakdown of O&M expenses by category for fiscal years 2014 through 2018 reflect the Authority's programs to continue to control and modestly reduce its portion of these expenses from recent levels. As discussed above, the O&M expenses excluding fuel and purchased power (referred to here as the Authority's Expenses) in fiscal year 2013 were 10.7% over the budget, which had been set aggressively low. These actual costs in fiscal year 2013 effectively matched the Authority's average Expenses over the prior three fiscal years and form the bases for the projected Expenses. The Authority's Expenses are budgeted to decrease by 2.3% in fiscal year 2014 from fiscal year 2013 actual costs; the reductions are in operations, while the maintenance budget is increased 9.1% for the same time frame. The Authority's Expenses budget is projected to drop 2.4% in fiscal year 2015, then increase 1.1% and 0.3% in fiscal years 2016 and 2017, and remain unchanged in 2018. The Authority has identified various cost reduction programs which were being evaluated at the end of the last fiscal year. Coupling these measures with reductions in the number of employees by attrition provides the bases for achieving the forecasted budgets of the Authority's Expenses.

The ratio of O&M expenses to total operating revenues in fiscal year 2013 was 85.0%, but is projected to be approximately 82% throughout the five-year forecast period, based in part on the reductions in O&M expenses discussed above.

NET REVENUES

Net Revenues, as defined under the Trust Agreement, are shown in *Appendix II, Income Statement,* as Balance to Revenue Fund. During fiscal year 2013 Net Revenues were $725,427,000, which was 13.8% more than the preceding year and 7.0% more than the average Net Revenues for the five fiscal years 2008 through 2012. For fiscal year 2014 net revenues are forecast to increase by 9.5% to $794,203,000. Net Revenues are forecasted to increase again in fiscal year 2015 by 3.6% and remain relatively stable through 2018, with projections of $823,142,000, $822,195,000, $840,048,000 and $848,439,000, respectively. Achieving these projected Net Revenues will depend on the Authority maintaining tight control over the Authority's Expenses as discussed above.

COMPARISON OF FY 2013 & FY 2014 BUDGETED TO ACTUAL EXPENSES
(in thousands)

Current Expenses	2013 Budget	2013 Actual Expenses	2013 Variance		2014 Budget	2014 Budget vs 2013 Actuals
Fuel Cost	$ 2,607,917	$ 2,603,578	$ (4,339)	-0.2%	$ 2,145,911	-17.6%
Purchased Power	740,867	755,686	14,819	2.0%	805,414	6.6%
Other Production (incl Hydro Plt)	55,181	71,655	16,474	29.9%	65,699	-8.3%
Transmission & Distribution	140,445	172,318	31,873	22.7%	158,731	-7.9%
Maintenance	212,872	213,890	1,018	0.5%	233,374	9.1%
Customer Actng & Collection	105,559	116,351	10,792	10.2%	115,369	-0.8%
Administrative & General	177,757	191,912	14,155	8.0%	175,510	-8.5%
Interest Charges	–	–	–	–	–	
Total	**$ 4,040,598**	**$ 4,125,390**	**$ 84,792**	**2.1%**	**$ 3,700,008**	**-10.3%**
Current Expenses Minus Fuel + Purch Power	$ 691,814	$ 766,126		10.70%	$ 748,683	-2.3%

DEBT SERVICE COVERAGE

Based on the amounts shown in *Appendix II Income Statement,* the Debt Service Coverage (DSC) was 1.38 in fiscal year 2013. The Debt Service Coverage is projected to be 1.41, 1.42, 1.39, 1.34 and 1.35 for fiscal years 2014 through 2018, respectively. As part of each year's budget the Authority develops a forecasted borrowing schedule to support its Capital Improvement Program through the subsequent five years. The projected annual debt service through fiscal year 2018 in the Authority's budget and this report was prepared prior to the planned financing scheduled for early fiscal 2014. In addition, the forecasted debt service requirements include capitalized interest to reduce early year obligations in future borrowings. These new financings may incur higher interest rates than forecasted and the ability to capitalize interest may be constrained as well. Both of these would increase the Authority's projected principal and interest requirements in the intermediate term, thereby lowering the forecasted debt service coverage ratio.

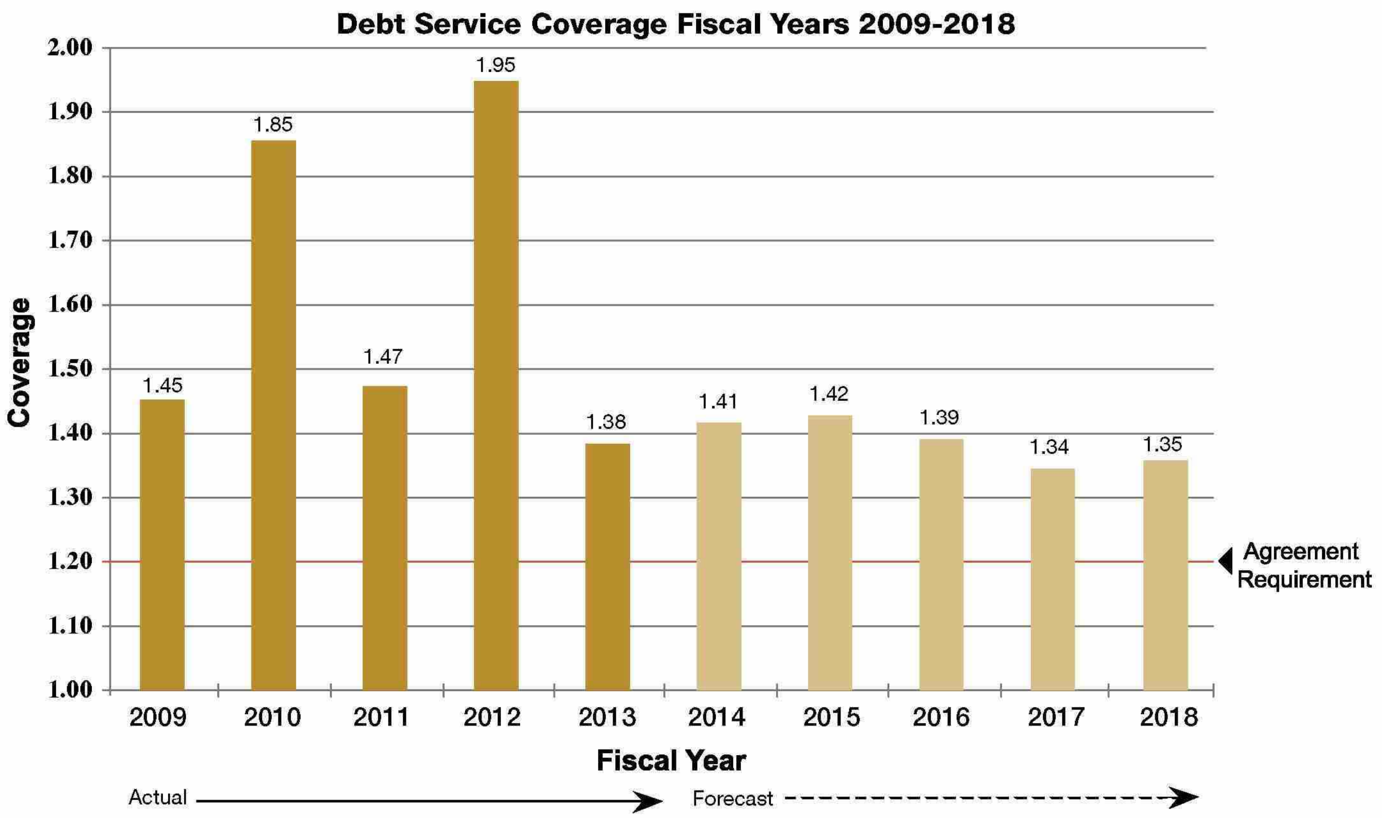
The Debt Service Coverage graph shows the five-year history and the five-year projection of the ratio of Net Revenues to Principal and Interest Requirements. The DSC in fiscal year 2012 was unusually high owing to the repayment schedule of the Series 2012 A/B financing in which capitalized interest and low early-year principal and interest payments resulted in the debt service being $267 million below the maximum (reached in 2017) and $199 million below the obligation for fiscal year 2013.

The projected DSC data are based on the sinking fund payments steadily increasing from $527.4 million in fiscal year 2013 to $626.2 million in fiscal year 2017. As discussed above and shown in *Appendix II Income Statement,* the Authority's forecasted growth in Net Revenues may not keep pace with the rate of increase in the debt service which actually unfolds.

DEPRECIATION EXPENSE

The actual depreciation accrual for fiscal year 2013 was $342,437,000, as shown in *Appendix IX, Depreciation Expense.* The estimates for the ensuing five fiscal years are $353,129,000, $363,723,000, $374,635,000, $385,874,000, and $397,450,000, respectively. Depreciation Expense is excluded from statements required for Trust Agreement purposes.

The Consulting Engineers issued a comprehensive depreciation review of the Authority's Plant-in- Service as of June 30, 2009. The results were implemented in fiscal year 2013 by the Authority. Compared with the previous study the results show that there is no longer a deficiency between the theoretical and booked depreciation reserves and the depreciation accrual rate should be reduced. The review confirmed statistically that the production plant's average service life continues to increase. It also showed that net negative salvage (cost of removal less salvage) of retired capital



equipment was no longer escalating at the rate that was shown in the previous study.

ACCOUNTS RECEIVABLE

The Authority reports its net accounts receivable for fiscal year 2013 was $1,494.2 million after an allowance of $251.3 million for uncollectable accounts which is 16.8% more than the previous year's amount. Of the $1,494.2 million, $603.0 million applied to government clients, an increase of 40.5% from the previous year, and $838.9 million applied to general clients, 2.4% less than the previous year. The remaining balance was mostly for unbilled services. The non-current account receivables balance for year end 2013 was $117.7 million or 15.7% more than the previous year's balance.

At the end of fiscal year 2013 the following five government agencies accounted for approximately 25% of Accounts Receivable balances owed to the Authority by Public Authorities:

Client	A/R Balance
Puerto Rico Sewer and Aqueduct Authority	$57.8 million
Department of Education	$30.5 million
Ports Authority	$31.6 million
Cardiovascular Center	$18.9 million
Urban Train Administration	$14.3 million

The Authority is continuing its aggressive effort to collect overdue accounts. The actions taken to collect from Public Authorities include working closely with the Office of Management and Budget to expedite payments. Actions taken for general clients include disconnecting electrical service, referring clients to collection and credit rating agencies, and setting up a payment schedule. In February 2011 the legislature of Puerto Rico approved Act 239-2011 that allows the Office of Management and Budget of the Commonwealth to estimate the monthly electric invoices of agencies that depend on General Fund allocations and to coordinate with the Puerto Rico Treasury Department to submit payments to the Authority at the beginning of each month. Since its adoption on December 11, 2011 the Treasury Department has been submitting current monthly payments for the electric energy consumed by the central agencies of the Commonwealth. Therefore the accounts receivable of these government agencies should not increase. As of June 30, 2013 the outstanding balances of public corporations was $216.1 million of which 41% was for past due accounts.

In an effort to collect account receivables from government agencies, in June 2013 the Authority's Executive Director appeared before the Commonwealth's legislature to request that a fund separate from the General Fund be set up to make payment for monies owed by government agencies.

CONTRIBUTIONS TO THE COMMONWEALTH

CONTRIBUTIONS IN LIEU OF TAXES AND OTHER

Since the Authority Act was originally enacted, the Authority has been required to make certain payments to the Commonwealth government and the island's municipalities as contributions in lieu of taxes (CILT). These payments were designed to be funded with an 11% mark up on electric sales— referred to as the Set Aside—and to be paid or credited from Net Revenues, as defined by the 1974 Agreement. Over the years the Commonwealth's legislature has revised and added certain subsidies and revised certain provisions of the payments to the municipalities, however, the basic framework of these contributions has remained. In reference to the disposition of Net Revenues as shown on *Appendix II, Income Statement,* the Authority considers the total amount of CILT and Other to include its contributions to the municipalities, plus three subsidies, an energy credit for qualifying businesses and the amortization cost of a settlement with the municipalities regarding disputed CILT obligations prior to 2004.

Although the intent of the Act was to have the Authority invoice and collect from the municipalities their electric invoices, the Authority has opted to offset monies owed for electric consumption with CILT.

For the last decade the contributions or credits to the municipalities have constituted more than three quarters of the CILT and Other total. In fiscal year 2013 the total current annual amount of CILT and Others was equal to 25% of the Authority's Net Revenues, compared to the prior five-year average of 31%. As discussed below, the most recent law establishing the Authority's CILT obligations provides for deferral of current year payments; since fiscal 2007 the Authority has deferred partial payment of an accumulating portion of the CILT. These obligations have been paid or credited from the Authority's Net Revenues after certain defined expenditures, subject to compliance with its obligations under the 1974 Agreement. While initially the contributions in lieu of taxes were paid to the Commonwealth's Secretary of the Treasury for distribution to the municipalities, for many recent years these contributions have amounted to a full credit to the municipalities for their electric power consumption.

In 1998, the Municipality of Ponce filed a complaint seeking payment from the Authority for the full amount of the contributions in lieu of taxes, plus a

potential addition based on available net revenues, for prior fiscal years. The island's other 77 municipalities subsequently joined the suit. The complaint challenged the Authority's disposition of net revenues in making deposits to certain funds under both the 1947 Trust Indenture and the 1974 Agreement for the purposes of paying the costs of capital improvements. The municipalities sought retroactive payment of the amount by which their share of the contributions in lieu of taxes had been reduced by such application. The Authority settled this litigation with the municipalities in 2004 by offering a monetary payment of $68 million and $57 million for electric infrastructure projects, for a total of $125 million. At the end of fiscal year 2013 the outstanding balance of the loan used for the monetary settlement was $9.7 million.

In 2004 legislation was enacted that revised the formula for computing contributions in lieu of taxes and set aside. The amended legislation requires the 11% mark up of the Authority's gross electric energy sales be distributed to fund all government rate subsidies programs, to pay contributions in lieu of taxes to the municipalities, to finance the Authority's Capital Improvement Program and for other legal purposes. The amendment changed the calculation of contribution in lieu of taxes payable to the municipalities in that it will be the greatest of the following three amounts:

1. twenty-percent of the Authority's Adjusted Net Revenues (Net Revenues, as defined in the 1974 Agreement), less the cost of government rate subsidies
2. the cost collectively of the actual annual electric power consumption of the municipalities;
3. the prior five-year moving average of the contributions in lieu of taxes paid to the municipalities collectively. If the Authority does not have sufficient funds available in any year to pay the contributions in lieu of taxes then the difference will be accrued and carried forward for a maximum of three years.

The Authority's municipal CILT obligation for fiscal year 2013 was $260.8 million, which was the value of the electric power consumed by the municipalities during the fiscal year. This represented an increase of more than 6% in the value over the previous year. As discussed below, Commonwealth Law 233 passed in 2011 offers the Authority the ability to exclude certain activities from municipal consumption that would qualify for the CILT obligation. The Authority is projecting a marked decline in their CILT obligation beginning in fiscal year 2014 as a result of provisions in Law 233.

The amount of $180.6 million for Contributions in Lieu of Taxes and Other shown on *Appendix II, Income Statement,* is the sum of the partial CILT credit for fiscal year 2013, plus the annual payments for the three previous year's unpaid CILT, plus certain subsidies and an annual amortization cost described below. During fiscal year 2013 the Authority was credited with $37.8 million in payments and services for the current year's obligations, the difference of $223.1 million will be carried forward for payment by the Authority over a maximum of three fiscal years. In fiscal year 2013 the Authority was also credited with $85.5 million towards the unpaid CILT balances from fiscal years 2010, 2011 and 2012 respectively; the installment for fiscal year 2010 completed the Authority's outstanding CILT obligations for that year. At the end of fiscal year 2013 the unpaid CILT balance totaled $323.6 million, an increase of $133.7 million over the previous year. The deferred CILT balance has grown steadily since the end of fiscal year 2007 when it was $34.3 million.

The Contributions in Lieu of Taxes and Other for fiscal year 2013 includes a total of $54.4 million comprised of three subsidies and an energy credit totaling $43.9 million and a payment of $10.5 million to amortize the outstanding line of credit used in the settlement of the lawsuit by the municipalities. As discussed in the *Rates* section the three subsidies are the hotel subsidy, the rural electrification and irrigation subsidy, and the residential fuel subsidy; the energy credit is the Authority's contribution based on the Economic Incentive Act, Law 73 (discussed below). The Authority's escalating costs under Law 73 for the fiscal years 2014 – 2018 are anticipated to be $2.2 million, $2.9 million, $3.7 million, $6.4 million, and $9.2 million, respectively.

In December 2011 the Commonwealth enacted Law 233 that clarified the scope of CILT by excluding the electrical consumption by municipalities used to subsidize revenues from for-profit activities, rental property generating income, and activities involving an entrance fee. The Authority has a program to identify and install additional meters to track this consumption which will reduce the municipal consumption subject to the CILT obligation; while identifying this consumption will not increase reported revenues, it will increase collectibles. The Authority has lowered the projected CILT for fiscal years 2014 through 2018 by $49 million annually to account for the revenues that Law 233 will generate.

Based on the adjusted municipal power consumption, plus the subsidies and energy credit discussed above, the Authority forecasts the CILT and Other costs for fiscal years 2014 through 2018 will be $201.0, $205.8, $208.9, $193.3, and $201.7 million, respectively.

The Authority's projected budgets and CILT amounts are structured to avoid increasing the accumulated deferred CILT balance of $323.6 million discussed above, assuming the forecasted annual CILT obligations are based on that current year's municipal power consumption. The applicable law, as discussed above, provides for the CILT to be the greatest of three amounts, however. With forecasted declines in municipal consumption, the prior five-year moving average of the contributions in lieu of taxes paid to the municipalities collectively would be greater than either 20% of Net Revenues or the current year's power consumption. Invoking the prior five year average criteria would increase the Authority's deferred CILT balance by $55.6 million in fiscal year 2014 and $46.9 million the following year, based on the budget for those years. These levels of CILT obligation cannot be sustained.

ECONOMIC INCENTIVES ACT

To spur economic development the Commonwealth Government enacted the Economic Incentives for the Development of Puerto Rico Act (Economic Incentives Act – Law 73) in May 2008. The Economic Incentive Act is scheduled to be in effect for ten years starting on July 1, 2008. In comparison to the Tax Incentives Act of 1998, which expired at the end of fiscal year 2008, the Economic Incentive Act expands the scope of businesses eligible for tax exemptions and credits. The three sections of the Economic Incentive Act that may most affect the Authority are the Energy Investment Credit, the Energy Cost Credit, and Wheeling. The tax credits in the Economic Incentive Act are based on the preferential income tax on Industrial Development Income.

The Energy Investment Credit section establishes a onetime tax credit of fifty percent for investments by eligible businesses in systems and equipment for generating electrical energy and for investments which improve efficiency. The energy generation may be for self consumption or for commercial resale. The amount of the tax credit for new self-generated capacity is limited to 25% of the eligible firm's income tax. The tax credit for commercial generation is limited to $8 million per eligible business and $20 million per year in the aggregate.

The Energy Cost Credit allows eligible businesses to receive a credit of 3% of the cost of their industrial energy consumption against income tax. Additional credits are available based on the number of employees and payroll cost up to a total maximum credit of 10% of the payments made to the Authority for energy consumed in the operation of the eligible business. The maximum credit will be reduced 1% per year between 2013 and 2017. The aggregate amount for this tax credit is capped at $75 million per fiscal year and $600 million through fiscal year 2018. The cost of the credits were borne by the Commonwealth's General Fund for the first year; beginning in fiscal year 2010 the Authority covered an escalating portion of the credit starting at 4% with uniform annual increases to 20% in fiscal year 2014, then 35%, 50%, 65% and 80% in fiscal years 2015 through 2018, respectively.

Under the Wheeling provision, the Authority was required to establish by January 2010 the technical criteria and tariffs that would apply to qualifying generators for moving their power—wheeling—on the Authority's system to the generator's clients or for the Authority to purchase the generator's power for general distribution to the Authority's clients The Authority held public hearings in 2010 and 2011 regarding proposed wheeling tariffs. Based on comments from these hearings and the public examiner's recommendations, the Authority has been evaluating its wheeling tariffs and has begun revision to its technical requirements for wheeling and interconnection. The Economic Incentive Act establishes a new administrative entity, the Energy Affairs Office, whose duties include overseeing the implementation of the wheeling provision. The Energy Affairs Office has the power to assign an arbitrator to establish rates between the Authority and a qualifying generator if there is a disagreement between the two parties.

Funding for the tax credits established by the Economic Incentive Act will be drawn from the Commonwealth's General Fund and from payments by the Authority, with the Authority's portion increasing during the term of the Act, as described above. The Authority's payments will be based on reductions in operating costs, improved efficiencies, revenues from wheeling and lower costs in purchased power. Under the law, the Authority's payments may not in any way be subsidized or passed through to its clients and the Authority is prohibited from reducing its number of employees or payroll. The tax credit will end if the Authority's average retail cost of power is 10 cents/kWh for two consecutive years. Prior to fiscal year 2012 the Authority had incurred only administrative costs associated with the Economic Incentive Act. In fiscal year 2012 the Authority contributed $866,000 for their 4% share of the total energy cred-

its assigned to nine qualifying businesses for fiscal year 2010. The Authority's contribution in fiscal year 2013 was $1.2 million. The escalating annual contributions under the Economic Incentive Act are projected to cost the Authority $53.1 million during the ten years the Act is in effect through fiscal year 2018.

FINANCING

LONG-TERM CAPITAL FINANCING

The Government Development Bank for Puerto Rico (GDB) is the primary fiscal agent for the Commonwealth of Puerto Rico and is responsible for overseeing and maintaining the Commonwealth's overall creditworthiness. In this capacity it coordinates all bond issues and lines of credit for the Authority as well as other agencies of the commonwealth government and municipal governments.

The Authority's actual and forecasted capital expenditures for fiscal years 2013 through 2018 are summarized by category in *Appendix VI, Capital Expenditures.* The projected expenditures as shown in *Appendix X, Details of Capital Improvement Program* are a breakdown by Budget Item Number of the expenditures shown in *Appendix VI.* The Authority's sources of funds and anticipated financing needs for fiscal years 2014 through 2018, as well as those realized in fiscal year 2013, are presented in *Appendix VII, Sources of Funds for Capital Expenditures.*

As of June 30, 2013, the Authority had $8,048,485,000 in Power Revenue Bonds outstanding. (See *Appendix V, Debt Service Coverage Under the 1974 Trust Agreement.*)

In April 2012 the Authority issued $650 million of Power Revenue and Power Revenue Refunding bonds. Ninety-three per cent of the proceeds were used to fund the following: Construction Fund, $359.5 million; pay down GDB line of credit, $161.9 million; and $82.6 million as capitalized interest. The approved amount of the line of credit issued by the GDB was $244 million of which $159 million had been used; the Authority paid $2.9 million in interest on the line credit, resulting in the $161.9 million total payment.

Amongst other uses, in fiscal year 2012 the GDB line of credit had been used to fund the Rate Stabilization Account which provided $79.4 million in credits to residential clients to reduce their fuel adjustment charges during fiscal year 2012 and for certain principal and interest payments due under the 1974 Agreement. The proceeds of Series 2012B bonds were used to refund Power Revenue Bonds Series II.

As shown in *Appendix VII, Sources of Funds for Capital Expenditures,* the Authority plans additional financing in fiscal years 2014, 2016 and 2018 principally to fund the Authority's Capital Improvement Program and other purposes.

INTERIM FINANCING

Lines of Credit and Notes Payable

As of the end of fiscal year 2013 the Authority had four lines of credit and one term loan.

The term loan financing relates to settled litigation with the municipalities of Puerto Rico, which amounted to $64.2 million. As of June 30, 2013 the balance was $9.7 million.

The first line of credit is for $25.4 million, intended for the restoration of the Isabela Dam. The outstanding balance as of June 30, 2013 was approximately $743,000. This line of credit expires on June 30, 2018. The Authority expects to be reimbursed by the Commonwealth Government for any payments made for this term loan.

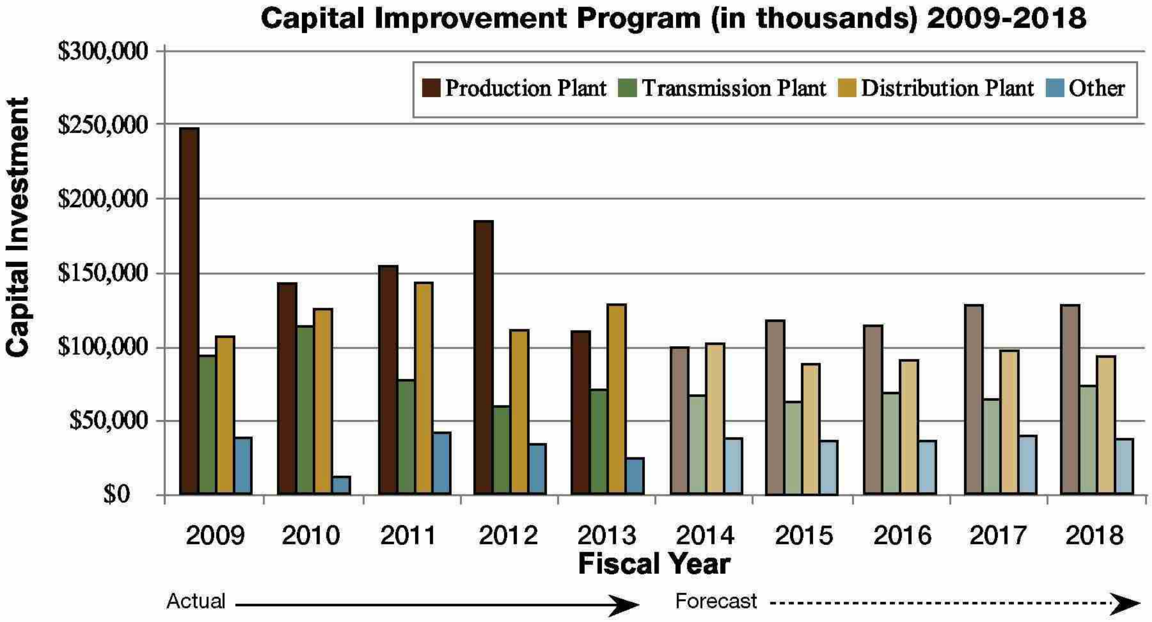
During fiscal year 2013 the Authority re-initiated a $100 million line of credit with the GBD for covering collateral on its power revenue bonds that are based on interest basis swaps. This line of credit expires on December 14, 2014. As of June 30, 2013 $6.1 million has been withdrawn and there was $93.9 million available for withdrawal.

The Authority has two other lines of credit to be used for fuel financing with two large commercial banks. The combined lines of credit amount to $750.0 million of which $744.4 million has been withdrawn leaving an available balance of $5.6 million.

CAPITAL IMPROVEMENT PROGRAM

The fiscal year 2014 Capital Improvement Program (CIP) projects a five-year period of expenditures for extensions and improvements to the System. An overview of the scope of these projects for fiscal year 2014 is provided below and is summarized by functional group in *Appendix VI, Capital Expenditures.* An expanded presentation of the CIP is in *Appendix X, Details of Capital Improvement Program,* which lists the extensions and improvements by Budget Item Number (BIN) through fiscal year 2018.

The Authority develops the CIP on the basis of supporting its objectives of providing dependable electric power service to the island of Puerto Rico at the lowest cost, consistent with applicable environmental and social obligations.



The Authority's capital expenditures reached a peak of $666.8 million in fiscal year 2008 when construction of the Authority's two newest production plant projects, San Juan Units 5&6 and the new combustion turbines at Mayagüez, were in their final phases. The capital expenditures in subsequent years dropped significantly. The average capital expenditures during the most recent past three fiscal years was $363.4 million which marked a decline of 46% from the 2008 peak.

Capital expenditures were projected to continue the decline in fiscal year 2013 with a budget of $300 million. Actual capital expenditures during fiscal year 2013 were $327.7 million; these were 6.7% less than the expenditures in fiscal year 2012, but 9.2% above the budget. During the next five fiscal years the Authority plans to reduce its level of annual capital expenditures to an average of $310.0 million, which is consistent with the actual expenditures in the past two fiscal years. The CIP budgets in millions of dollars are projected to be $300.0, $300.0, $300.0, $325.0 and $325.0 for fiscal years 2014 through 2018, respectively. The figures do not include the Contributions in Aid of Construction, i.e., capital contributed by either the Authority's clients, FEMA or the Commonwealth Government for special construction services. However, allowance for funds used during construction (AFUDC) and annual cost escalations are included.

The tabulated data show by functional group the amounts budgeted for the Capital Improvement Program, the amounts actually expended in fiscal year 2013 and the budget for fiscal year 2014. During the course of the year the Authority occasionally reallocates certain budgets, staying within the total frame work. The budget amounts shown in the table do not reflect any reallocations.

As indicated, the Authority's total CIP budget for fiscal year 2014 is unchanged from the previous fiscal year, but the allocations by function group have been revised to reflect completion of projects and current priorities; the budget for fiscal year 2014 is 8.4% less than the previous year's actual expenditures.

In the past fiscal year the Authority contributed $17.0 million from internal funds to the Capital Improvement Fund, which was 5.2% of the total expenditures for the year. During fiscal year 2014 the Authority

COMPARISON OF BUDGETED CIP TO ACTUAL CIP EXPENDITURES – FY 2013

(in thousands)

	Budget	Actual	Difference		Budget 2014	2014 vs Actual 2013
Production	$118,898	$ 107,810	($11,088)	-9.3%	$ 96,375	-10.6%
Transmission	58,965	69,661	10,696	18.1%	66,347	-4.8%
Distribution	91,097	127,926	36,829	40.4%	99,884	-21.9%
Other	31,040	2,280	(8,761)	-28.2%	37,394	67.8%
Total	**$ 300,000**	**$ 327,677**	**$ 27,677**	**9.2%**	**$ 300,000**	**-8.4%**

plans to contribute $22.7 million, which is 7.6%, to the Capital Improvement Program budget for the year. Funding for the Capital Improvement Program is discussed further in the *Capital Improvement Fund* section of Funding Recommendations below.

The first year of the Authority's five-year Capital Improvement Program is included in the Annual Budget of Current Expenses and Capital Expenditures which is reviewed and approved by the Consulting Engineers prior to the beginning of each fiscal year. The current CIP through fiscal year 2018 includes funds to complete the planned conversions to dual fuel firing of oil and natural gas at the Authority's large steam-electric production units and its combined cycle units. As discussed in the Capacity and *Energy Resource Planning* section, providing natural gas to most of the converted units will require an extensive gas supply infrastructure, with the exception of the Costa Sur units for which the gas supply pipeline is in service. Since the Authority plans that the gas supply infrastructure will be developed with alternative sources, funds are not included in the Authority's CIP for this work.

We believe that the moneys shown in the CIP for extensions and improvements to the System over the forecast period are reasonable. The CIP is comprised of numerous budget items grouped into five general categories. The largest expenditures are in production plant, transmission plant, and distribution plant. The Capital Improvement Program chart shows the trends and relative values of these groups over the five-year budget period.

PRODUCTION PLANT

The CIP for fiscal year 2014 includes $96.4 million for production plant related projects. All of these are considered rehabilitation projects. The scope of these includes work associated with dual fuel conversion to include natural gas, improvements to boilers and steam turbines, as well as environmental projects.

As discussed in *Diesel Generators in the Production Plan*t section, the planned production plant CIP includes replacing old diesel generator capacity on the small island of Culebra with new equipment. Civil work on the project began in fiscal year 2013, with the full scope scheduled for completion in fiscal year 2015. The new generators will improve the reliability of service to Culebra, especially by reducing service interruptions from heavy weather.

The principal focus for rehabilitation projects is the major refurbishment work planned for the Authority's operating production plants during scheduled major overhauls and plant system upgrades. A representative scope of these projects is discussed in the *Production Plant* section for each plant. Within the CIP for production, boiler improvements account for approximately one quarter of the fiscal year 2014 budget. In addition to the fuel conversions discussed below, the scope includes refurbishing major boiler components such as waterwalls and ductwork, refurbishing and improving boiler structural steel and platforms and the procurement of a shared spare boiler feed pump internals for the largest four steam plants. Improvements to the steam turbines and the balances of the steam plants constitute approximately another quarter of the production CIP budget for fiscal year 2014. These activities include the planned improvements to the steam turbine at Aguirre Unit 2, replacing four high pressure feedwater heaters at Costa Sur Unit 5 & 6, refurbishing water storage tanks, and the upgrade and expansion of the demineralized water treatment plant at the Costa Sur station. The CIP projects at production plants include improvements to various major systems at combined cycle, combustion turbine, and hydroelectric plants.

The CIP for fiscal years 2014 through 2018 includes $70.2 million to complete the conversion to dual fuel firing capability, i.e. fuel oil and natural gas, at the Authority's eight largest steam plant units at Costa Sur (already completed), Aguirre, Palo Seco and San Juan. This is consistent with the Authority's strategy for MATS compliance as discussed in the *Environmental* section. The CIP for fiscal years 2014 through 2018 also includes $10.0 million for adding natural gas firing capability to the combined cycle plants at San Juan Units 5 & 6, which presently fires distillate.

The Authority has identified projects within the rehabilitation category that are for pollution control, or for environmental issues, that have a total value of $10.8 million for fiscal year 2014. Environmental projects include installing new continuous emissions monitoring systems (CEMS) at the steam plants in preparation for MATS compliance, cooling water pollution control projects, and oil spill containment, prevention, control and countermeasures.

TRANSMISSION PLANT

The CIP for fiscal year 2014 includes $66.3 million for transmission plant related projects. Expansion projects are budgeted at $26.7 million and rehabilitation projects have a budget of $39.7 million.

The expansion projects are the new transmission lines, transmission centers, switchyards, high voltage equipment, and extensions at existing facilities to

support the growth of the transmission system. The major planned projects for the 230, 115 and 38 kV systems are described in the *Transmission* section. These projects include the new 230 kV line from Costa Sur to Cambalache, the new 115 kV GIS switchyard at San Juan steam plant, the new 115/38 kV transmission centers at Barranquitas and Bairoa and new 38 kV underground projects in various municipalities around the island.

Improvements to the 230, 115 and 38 kV systems constitute the rehabilitation projects. These include replacement of structurally deteriorating lines and poles, especially in the 38 kV system, and the upgrading of the supervisory control and data acquisition (SCADA) system.

DISTRIBUTION PLANT

The distribution system CIP budget for fiscal year 2014 is $99.9 million and is comprised of $18.8 million for expansion projects and $81.1 million for rehabilitation projects.

The distribution expansion projects include new substations and increases to the capacity of existing substations. These scopes are represented by the 13.2 kV substations at Sea Land (Caparra), Añasco and Charco Hondo. The expansion projects also include new underground distribution lines, temporary substations and portable equipment, new 13.2 kV feeders, and work associated with service to new clients.

The rehabilitation projects to the distribution system include improvements to existing substations and line facilities, replacement of distribution poles and lines, and the improvement of underground distribution lines. Consistent with its widespread application, approximately 31% of the distribution CIP budget is directed to improvements for aerial distribution lines throughout the island. The rehabilitation scope includes the underground work in the historic district of Ponce, that is budgeted for $3.0 million in fiscal year 2014. The largest project in this category is directed to the purchase of remote read meters, which accounts for more than 9% of the distribution CIP budget. The balance of the distribution projects addresses numerous miscellaneous requirements such as the purchase and installation of breakers, sectionalizers, voltage regulators, capacitors, and similar distribution equipment and systems.

GENERAL PLANT

The fourth category within the CIP is the general plant which for fiscal year 2014 totals $33.8 million. This category is composed of $7.2 million for general land and buildings and $26.6 million for equipment.

General land and buildings includes funds for the acquisition of land and rights of way and for structures. The land acquisition for new transmission line rights of way represents approximately 40% of this budget. Regarding structures and buildings, the general plant funds are for improvements to technical offices, buildings, warehouses, workshops and customer service facilities. The budget includes funds for the rehabilitation of facilities at the Authority's head quarters, the Luchetti building in San Juan.

The equipment group is made up of five subgroups. The CIP for fiscal year 2014 includes $619,000 for office equipment. In fiscal year 2014 the computer equipment budget is $5.0 million. Other equipment subgroups are transportation equipment (land and air) at $8.3 million, of which $7.8 million is for new trucks and vehicles. The fiscal year 2014 budget for communications equipment is $4.2 million, which includes $3.3 million for upgrading the fiber optic and microwave systems for SCADA. The budget for other equipment is $8.5 million. This includes a wide range of specialized tools and equipment, such as construction tools, directional drilling rigs, environmental and planning analytical tools, and maintenance tools.

PRELIMINARY INVESTIGATIONS

The final category in the CIP is for preliminary studies and surveys. The fiscal year 2014 budget for these activities is $3.6 million. These studies are principally performed by the engineering, planning and environmental groups to support the evaluations of various system improvements and environmental compliance alternatives. The scope of studies includes evaluating the integration of renewable energy sources into the electric system. Other studies evaluate improvements to the operation and maintenance of the transmission and distribution system.

FUNDING OF THE EMPLOYEES' RETIREMENT SYSTEM

The Employees' Retirement System of the Authority is a separate trust fund created and administered by the Authority. The Retirement System is funded by contributions from both the Authority, based on annual actuarial valuations, and plan members. The Retirement System's independent actuary prepared an actuarial valuation for fiscal year 2012. The actuarial evaluation concluded that: The valuation results indicate that the combined employer and member contribution rates are sufficient to fund the normal cost for all members and the unfunded accrued liability. The valuation report also states that the actuarial assumptions meet the parameters for the disclosures under Governmental Accounting Stan-

dards Board Statements No. 25 and 27 and that the employer contribution rate is sufficient to finance the promised benefit under Statements 25 and 27.

The Retirement System's unfunded accrued liability had increased from $1,512.6 million as of the end of fiscal year 2011 to $1,700.9.6 million as of the end of fiscal year 2012. For future calculations the Actuarial assumptions are: an 8.5% annual rate of return on investments; projected annual salary increases of 4.1 – 5.4% depending on age; 2 – 8% cost of living adjustments depending on the amount of benefit with a minimum of $25 per month and maximum of $50 per month; and 3% inflation.

The following table further summarizes the status of the Authority's Pension Plan for the year ending June 30, 2012:

AUTHORITY'S PENSION PLAN

Number of Active Members	8,600
Number of Retired and Disabled Members and Survivors	10,975
Annual Benefits	$191,526,901
Actuarial Value of Assets (in millions)	$1,285.4
Actuarial Accrued Liability (in millions)	$2,986.3
Unfunded Actuarial Accrued Liability (in millions)	$1,700.9
Estimated Covered Payroll (in millions)	$365.0
Recommended Contributions for Fiscal Year Ending 2014	
Total Contribution Rate:	
Normal	9.5%
Unfunded Accrued Liability	30.2%
Total Contribution Rate	39.7%
Average Member Contribution Rate	10.4%
Authority Contribution Rate	29.3%
Amortization Period	28 years

INVENTORIES AND OTHER PROPERTIES

As part of the Finance Directorate, the Material Management Division's mission is to support all of the Authority's installations with the material and equipment necessary to accomplish the Authority's goal of providing electric service to clients at the lowest possible cost. The Warehouses subdivision utilizes 32 warehouses and manages an extensive inventory. At the end of fiscal year 2013 the inventory was worth $217.7 million of which $85.9 million was transmission and distribution material and $109.2 was related to its production plant spare inventory and $22.6 was general inventory. The spare parts inventory for transmission and distribution plant includes the safekeeping of a number of items, such as: transformers; poles; fuses; breakers; structures; and insulators. Among the items for production plant the inventory includes: spare rotors for units at the Aguirre and Costa Sur Steam Plants; and a spare turbine rotor for Palo Seco Units No. 3 & 4. For a (partial) list of spare components for the production plant refer to the *Spare Components* section in the *System's Operations* section.

INSURANCE

The Risk Management Office, within the Finance Directorate, manages the Authority's Insurance Program. It is responsible for managing and controlling the Authority's resources to minimize risks of accidental losses. In addition, it analyzes, assesses, and recommends insurance policies and bonds for contracts and purchase orders. It settles property claims against the Authority valued at less than $10,000.

During fiscal year 2013 the Authority maintained a layered set of All Risk Property and Boiler and Machinery policies that provided coverage of $750 million. The structure of the program includes independent layers of $200 million each for coverage for all risks, and boiler and machinery losses. In excess of these $200 million layers of coverage, the Authority's insurance program includes a $350 million of combination of all risks and boiler and machinery coverage, providing up to a $750 million limit of coverage for a combined all risks and boiler and machinery loss. Transmission and distribution lines other than underground and fiber optic lines are excluded which is common in the electric utility industry.

The Authority retains the first $25 million in earthquake losses, the first $25 million in windstorm loss, plus an additional $20 million of windstorm loss in the $100 million excess of $100 million layer of coverage for a total of $45 million retention for windstorm damages, and $10 million in boiler and machinery losses. The retentions under all other covered losses include a $2 million deductible and, $7.5 million of the first $25 million for coverage of all other covered loss retention totaling $9.5 million.

The business interruption coverage within the All Risk Property Policy is capped at $300 million with the Authority covering the costs from the first thirty days of the interruption.

In addition to the two policies cited above the Authority's Insurance Program contains policies for Public Liability, Commercial Auto Policy-PREPA, Personal Auto Policy-Employees, Crime, Directors and Officers Liability, Fiduciary Liability, Employment Practices Liability, Aviation, Hull and Hull Risks, Personal Accident and Health, Owner Controlled Insurance Program (OCIP) Rolling Wrap-up, and

Open Cargo. Among the policies included in the OCIP are; Commercial General Liability, Builders Risk Installation Floater, Pollution Liability and Professional Liability. The public liability coverage remains at $75 million with the Authority holding $1 million self-retention and $1 million deductible / $2 million annual aggregate deductible.

The Eleventh Supplemental Agreement created the position of "Independent Consultant", a consultant or consulting firm or corporation to be employed by the Authority under Section 706 of this Agreement to carry out the duties of said Independent Consultant. Section 706 of the 1974 Agreement reads in part:

> *The Authority covenants and agrees…it will, for the purpose of carrying out the duties imposed on the Independent Consultant by this Agreement, employ one or more independent firms having a wide and favorable repute in the United States for expertise in risk management and other insurance matters related to the construction and operation of electric systems. It shall be the duty of the Independent Consultant to prepare and file with the Authority and the Trustee at least biennially, on or before the first day of November, beginning November, 1999, a report setting forth its recommendations, based on a review of the insurance then maintained by the Authority in accordance with Section 707 of this Agreement and the status of the Self-insurance Fund, of any changes in coverage, including its recommendations of policy limits and deductibles and self-insurance, and investment strategies for the Self-insurance Fund.*

The cost of the Authority's Insurance Program as renewed with these changes is approximately $24.7 million a 15% savings from the previous Insurance Program renewal.

The Tenth Supplemental Agreement created the Self-insurance Fund. This fund is to be used to pay for the cost of repairing, replacing, or reconstructing property damaged or destroyed from or extraordinary expenses incurred as a result of a cause that is not covered by insurance. It can also be used, when approved by the Consulting Engineers, to cover loss of income due to a cause which is not covered by insurance. The moneys in the Self-insurance Fund allow the Authority to increase its insurance deductibles, thereby lowering its insurance premiums. Refer to the *Funding Recommendations* section for the status of the Self-insurance Fund and the Consulting Engineer's recommendations concerning contributions.

FUNDING RECOMMENDATIONS

Section 706 of the 1974 Agreement reads in part: it shall be the duty of the Consulting Engineers to include in such report [this Annual Report] their recommendations as to the amount that should be deposited monthly during the ensuing fiscal year to the credit of the Reserve Maintenance Fund…, deposited during the ensuing fiscal year to the credit of the Self-insurance Fund…and deposited during the ensuing fiscal year to the credit of the Capital Improvement Fund.

These three funds were created and funded in 1996 when the 1947 Trust Indenture was defeased.

There have been four major events that have caused losses to the Authority since the Reserve Maintenance and Self-insurance Funds were created.

The first was Hurricane Hortense in fiscal year 1997 that caused an estimated $36.0 million in damages to the Authority's System. The entire loss of this event was borne by the Authority.

In fiscal year 1999 Hurricane Georges devastated the island. Total damages to the System were estimated at $239.9 million of which $12.7 million was covered by insurance, $168.0 million was provided by the Federal Emergency Management Agency (FEMA) and the remainder of $59.2 million was the responsibility of the Authority.

Tropical Storm Jeanne in fiscal year 2005 caused an estimated $60 million in damages to the System, of which FEMA provided $11.8 million in aid and the balance of $42.8 million came from various funds of the Authority.

The fires at the Palo Seco Power Plant during fiscal year 2007 caused losses estimated to total $363.2 million, of which insurance payments to the end of fiscal year 2012 amounted to $301.3 million.

In August 2011 Hurricane Irene (later Tropical Storm Irene as it traveled northward) passed by the north coast of Puerto Rico. While the storm caused wind and flood damages and extensive power outages, its impact was significantly less than the events described above. The Authority submitted claims to FEMA for $15.9 million, but had not received any payments during the past fiscal year.

The specific utilizations of money from the Reserve Maintenance and Self-insurance Funds are discussed below.

RESERVE MAINTENANCE FUND

Section 512 of the 1974 Agreement reads in part:

> *moneys held for the credit of the Reserve Maintenance Fund shall be disbursed only for the purpose of paying the cost of unusual or extraordinary maintenance or repairs, maintenance or repairs not recurring annually and renewals and replacements, including major items of equipment.*

At the end of fiscal year 2013, the Reserve Maintenance Fund's balance was $15.8 million. The Reserve Maintenance Fund is a restricted fund in which the moneys are held in trust by the Authority.

Since the fund was created in 1996 there have been two instances when the Authority withdrew moneys from this fund.

The first instance occurred in fiscal year 2005, when $7.1 million was withdrawn and applied as part of the $45 million costs to repair the System following damages caused by Tropical Storm Jeanne. Additional sources of funds to restore the System came from FEMA and the Authority's Self-insurance Fund.

The second instance began in April 2007 when the Authority sought the Consulting Engineers' concurrence regarding the use of the Reserve Maintenance Fund as an interim source of funds for increased costs associated with the loss of the Palo Seco Steam Plant. The Consulting Engineers concurred, but stipulated that any moneys withdrawn from the Reserve Maintenance Fund should be replenished using the proceeds from the Authority's insurance program within a reasonable timeframe. Consistent with the Consulting Engineers intent, the Authority borrowed $9.4 million from the Reserve Maintenance Fund during fiscal year 2007 and $58.3 million during fiscal year 2008, a total of $67.7 million. The withdrawals were carried as an inter-fund debt of the General Fund as part of the Palo Seco Steam Plant recovery project. During the same period the Authority returned $14.7 million from insurance proceeds, $5.0 million in fiscal year 2007 and $9.7 million in fiscal year 2008, netting a $53 million inter-fund debt of the General Fund to the Reserve Maintenance Fund.

Consistent with the Consulting Engineers responsibilities under the 1974 Trust Agreement, the Consulting Engineers recommended that the Authority deposit $5 million to the Reserve Maintenance Fund in fiscal years 2009, 2010 and 2011. At the request of the Authority, the Consulting Engineers agreed that the moneys would instead be used to reduce the $53 million inter-fund debt; at the end of fiscal year 2013 this inter-fund debt was approximately $33 million.

The Consulting Engineers recommends the Authority need not deposit any moneys into the Reserve Maintenance Fund during fiscal year 2014.

SELF-INSURANCE FUND

Section 507 (g) of the 1974 Agreement reads in part:

> *to the credit of the Self-insurance Fund...such amount, if any, of any balance remaining after making the deposits under clauses (a), (b), (c), (d), (e), and (f) above, as the Consulting Engineers shall from time to time recommend; and*

Section 512A of the 1974 Agreement reads in part:

> *moneys held for the credit of the Self-insurance Fund (1) shall be disbursed...only for the purpose of paying the cost of repairing, replacing or reconstructing any property damaged or destroyed from or extraordinary expenses incurred as a result of a cause which is not covered by insurance…or (2) shall be transferred to the Revenue Fund in an amount, approved by the Consulting Engineers, equal to the loss of income from the System as a result of a cause which is not covered by insurance.*

Section 512A of the 1974 Agreement further reads:

> *If the Authority shall have determined that all or any portion of the moneys held to the credit of the Self-insurance Fund is no longer needed for the purposes specified in the second preceding paragraph, the Authority may withdraw an amount equal to such portion from the Self-insurance Fund and transfer such amount to the credit of the Bond Service Account; provided, however, that no such transfer shall be made prior to the time that the Consulting Engineers shall have approved such transfer in writing.*

As of the end of fiscal year 2013 the balance of the Self-insurance Fund was $92.2 million. Similar to the Reserve Maintenance Fund, the Self-insurance Fund is a restricted fund in which the moneys are held in trust by the Authority. The Authority has withdrawn moneys from this fund four times since its creation in 1996. The first withdrawal, in fiscal year 1997 for $32 million, was for damages caused by Hurricane Hortense. The second withdrawal for $30 million in fiscal year 1999 was for damages caused by Hurricane Georges. Then in fiscal year 2005 for damages caused by Tropical Storm Jeanne $18.3 million was withdrawn. It should be noted that these amounts were used to supplement insurance payments and reim-

bursements from FEMA. They represented only a fraction of the moneys required to restore the Authority's facilities.

In fiscal year 2007, at the request of the Authority, the Consulting Engineers authorized the withdrawal of moneys from the Self-insurance Fund to cover uninsured losses associated with the Palo Seco Steam Plant fires. During fiscal year 2008 the Authority withdrew $25.4 million from this fund for the uninsured losses associated with the Palo Seco Steam Plant fires. Also during fiscal year 2008 the Authority deposited $5.0 million to this fund. The Authority deposited to the fund $10 million per year in fiscal years 2009, 2010 and 2011 and $5 million in fiscal year 2012 in accordance with the Consulting Engineers recommendations.

In August 2011 Hurricane Irene (later Tropical Storm Irene as it traveled northward) passed by the north coast of Puerto Rico. While the storm caused wind and flood damages and power outages to more than one million clients, its impact was significantly less than the events described above which required withdrawals from the Self-insurance Fund. During fiscal year 2012 the Authority submitted claims to FEMA for $15.9 million. At the end of the past fiscal year the Authority had not yet received any payments, but did not plan to use the Self-insurance Fund for this event.

During fiscal year 2014 the Consulting Engineers recommends the Authority need not deposit any moneys into the Self-insurance Fund.

CAPITAL IMPROVEMENT FUND

Section 507 (h) of the 1974 Agreement reads in part:

> *to the credit of the Capital Improvement Fund such amount, if any, of any balance remaining after making the deposits under clauses (a), (b), (c), (d), (e), (f), and (g) above, as the Consulting Engineers shall recommend as provided by Section 706 of this Agreement; provided, however, that if the amount so deposited to the credit of said Fund during any fiscal year of the Authority shall be less than the amount recommended by the Consulting Engineers, the requirement therefore shall nevertheless be cumulative and the amount of any such deficiency in any such fiscal year shall be added to the amount otherwise required to be deposited in each fiscal year thereafter until such time as such deficiency shall have been made up, unless such requirement shall have been modified by the Consulting Engineers in writing, a signed copy of such modification to be filed with the Authority.*

Section 512B of the 1974 Agreement reads in part:

> *Moneys held for the credit of the Capital Improvement Fund shall be disbursed...only for paying the cost of anticipated extensions and Improvements of the System the cost of which has not otherwise been provided for from the proceeds of bonds issued under the provisions of this Agreement.*

The Consulting Engineers approves annually the Authority's budget for the ensuing fiscal year; the budget includes amounts for the first year of the five-year Capital Improvement Program (CIP). (for further discussion, refer to the Annual Budget in the *Financial* section) The budget for fiscal year 2013 projected that the CIP expenditures would be $300.0 million, of which $27.0 million of the Capital Improvement Fund would be generated internally. The actual CIP expenditures for fiscal year 2013, however, totaled $327.7 million, of which $17.0 million, or 5.2%, was financed internally through the Capital Improvement Fund. In the five fiscal years from 2009 through 2013 the average level of internal funding for the CIP was 5.9%; this low average would have been even lower except for the contributions made in 2010. The levels of deposits to the Capital Improvement Fund reflect the sensitivity of this funding to the Authority's compliance with operating budgets and its obligations of Contributions in Lieu of Taxes.

For fiscal year 2014 the Capital Improvement Program budget is $300.0 million, of which $22.7 million, or 7.6%, is projected to come from internal funds. The internally generated funds portions of the CIP for fiscal years 2015 through 2018 are projected to be 10.4%, 4.3%, 4.0% and 4.0%, respectively. The forecasted amount of internal funds will average 6.0% of the CIP over the five years ending in fiscal year 2018.

The following table shows the Authority's actual deposits to the Capital Improvement Fund for the most recent five fiscal years compared with that which was budgeted.

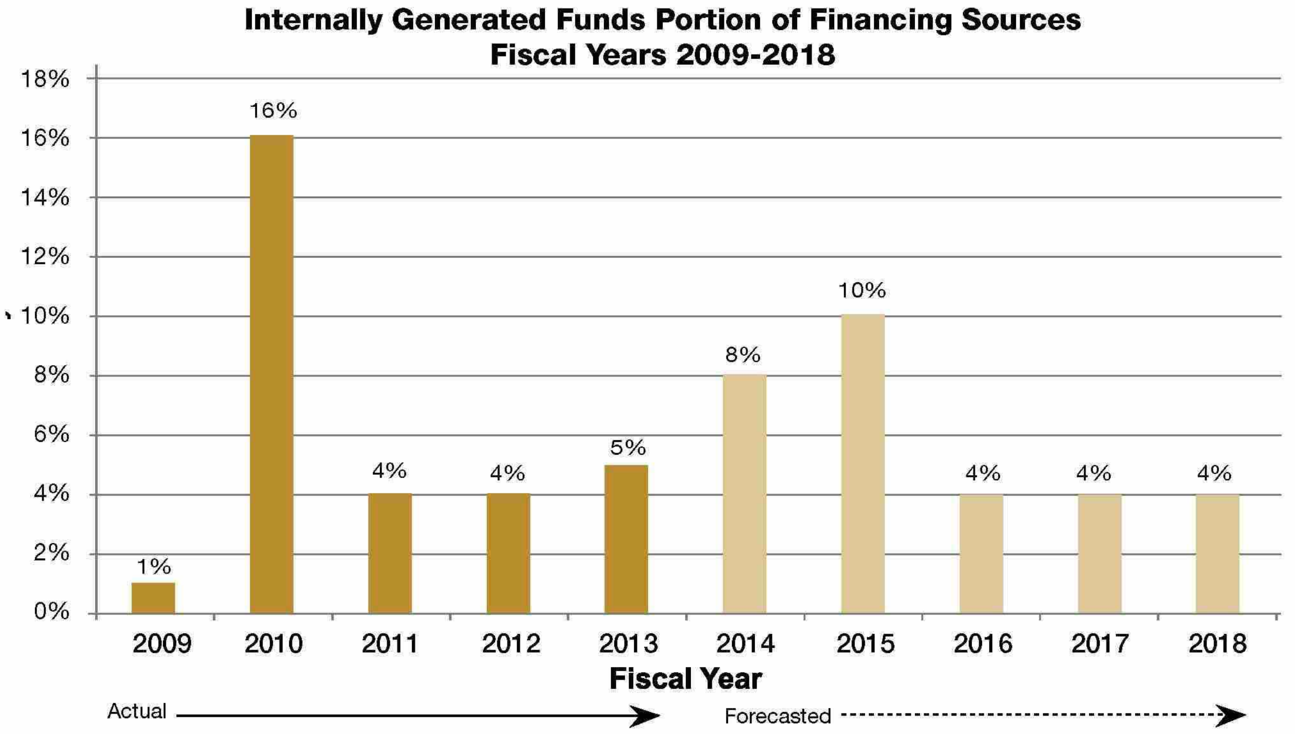
CAPITAL IMPROVEMENT FUND

Fiscal Year	Amount Budgeted	Amount Deposited	Difference
2013	$27.0	17.0	($ 10.0)
2012	$77.3	15.1	($ 62.2)
2011	$69.1	17.2	($ 51.9)
2010	$0.0	63.4	$ 63.4
2009	$0.0	4.7	$ 4.7

The Capital Improvement Fund also serves as an additional reserve for the payment of the principal of

and the interest on the Power Revenue Bonds and meeting the amortization requirements to the extent that moneys in the 1974 Sinking Fund, including the 1974 Reserve Account, in the Reserve Maintenance Fund, and in the Self-insurance Fund are insufficient for such purpose.

The chart presents the annual portions of internally generated funds for the total financing sources of capital expenditures since 2009 and those forecasted through 2018.



HUMAN CAPITAL

HUMAN RESOURCES

On June 30, 2013, the Authority had a workforce of 8,465 employees: 8,025 permanent employees, and 390 temporary or probationary employees who had been employed by the Authority for less than 12 months. The total number of employees on June 30, 2013 reflects a net decrease of 161 employees from the previous year. This decrease includes one employee who was classified as an emergency employee in fiscal year 2012. During the past fiscal year the number of permanent employees declined by 263, while the number of temporary employees increased by 103. Approximately 90% of those leaving the Authority in the past fiscal year retired; in the same year the Authority hired 200 new employees. The Authority anticipates that the recent rate of decline in the number of permanent employees will continue through fiscal year 2014. At the end of fiscal year 2012 the Authority had 8,626 employees; of which 8,338 were permanent and 287 were temporary.

The Authority is comprised of eight directorates and the Governing Board. The directorates are the Executive Directorate, the Generation Directorate, the Transmission & Distribution Directorate, the Law Directorate, the Planning and Environmental Control Directorate, the Finance Directorate, the Client Services Directorate, and the Human Resource and Labor Affairs Directorate. Ninety–three percent of the Authority's permanent employees were employed in one of the following four directorates: 3,309 worked in the Transmission & Distribution Directorate for a total of approximately 40% of the Authority's employees; 1,951 employees worked in the Generation Directorate for a total of 24% of the Authority's employees; the Client Services Directorate employed 1,441 persons or 18% of the Authority's workforce; and 808 employees worked in the Executive Directorate, constituting approximately 10% of the Authority's workforce. An additional 589 persons were employed in one of the four other directorates or by the Governing Board.

In an effort to achieve long term cost savings, in September of 2009 the Authority implemented a major change in the manner in which medical insurance would be provided for retirees and their spouses. Before September 1, 2009 an employee retiring with 25 years of service received medical care insurance for themselves and their spouse. After September 30, 2009 an employee retiring with less than 30 years of service was not eligible for a lifetime benefit of medical insurance for themselves or their spouse. An employee retiring after that date with more than 30 years of service received a lifetime benefit of medical insurance but received no medical insurance coverage for their spouse. The Authority put in place a plan whereby former employees with 30 years of service can purchase coverage for their spouse. The Authority has negotiated an extension of the firm fixed price for the provision of medical care for retirees and eligible spouses through December of 2013.

The Authority prepares its employees for their job assignments by providing a wide range of training programs and refresher training programs. The Human Resources Directorate provides the Authority's employees with training in the areas of safety, health, and computer usage. The training programs offering job specific, technical knowledge of the type needed by the employee to effectively perform their assigned work are provided by the directorate within which they are employed. Bargaining and non-bargaining unit employees, supervisors and managers participate in these programs.

LABOR AFFAIRS

The following paragraphs provide an overview of the bargaining units within the Authority and of the status of the labor agreements applicable to these bargaining units.

During fiscal year 2013 four different unions represented 70% of the Authority's 8,465 permanent and temporary employees. The largest union is the Electric Industry and Irrigation Workers Union, known by its Spanish acronym (UTIER). At the end of the past fiscal year UTIER represented 4,717 employees engaged in operations and maintenance. The other three unions are the Insular Union of Industrial Workers and Electrical Construction, Inc. (UITICE), with 839 construction workers; the Independent Professional Employees Union (UEPI), with 360 professional employees, and the Puerto Rico Electric Power Authority Pilots Union (UPAEE), with six pilots. The other 2,592 employees are members of the executive, managerial, and administrative staff: the terms of employment for these employees are not established by a collective bargaining agreement. The figures for fiscal year 2012 were similarly proportional; 6,006 employees represented by unions, (70% of the workforce), and 2,620 in executive, managerial, and administrative positions.

The following paragraphs describe the status of the renegotiations of the Authority's four collective bargaining agreements. During these negotiations the Authority has proposed language that reaffirms certain management rights, clarifies job descriptions, and modifies the code of conduct in a manner that will facilitate the management of its operations. The Authority is attempting to negotiate a reduction in accident leave benefits to bring them more in line with the private sector and to reduce certain sick leave benefits for new employees. The Authority has stressed that the current economy makes concessions on the part of the unions a prerequisite of a monetary offer. Nevertheless, during the collective bargaining process the Authority strives to negotiate reasonable and equitable terms for the Authority and its employees.

Labor agreements establishing wages, hours, and conditions of employment for three of the Authority's four unions terminated during fiscal 2011; these expirations were agreements with the Pilots (UPAEE), the Independent Professional Employees Union (UEPI), and Insular Union of Industrial and Electrical Construction Workers (UTICE). The agreement with Electric Industry and Irrigation Workers Union (UTIER), the largest union, expired in early fiscal year 2013. All renegotiations continued without settlement during fiscal year 2013.

The Authority and representatives of UTIER began the renegotiation of their collective bargaining agreement during fiscal year 2011 approximately eighteen months prior to the agreement's expiration in fiscal year 2013. During fiscal year 2013 employees represented by UTIER held sporadic one day or partial day strikes, plus a two week work action beginning in October 2012.

The Authority began the renegotiation the collective bargaining agreement with the Pilots (UPAEE) in June 2010. The four-year agreement, which established wages, hours, and conditions of employment for the Authority's six pilots, terminated in July 2010. At the end of fiscal year 2013 the parties were still in negotiations.

Negotiations for a new collective bargaining agreement between the Authority and UEPI, which represented 360 of the Authority's employees, were continuing at the end of fiscal year 2013. The Authority is seeking a three year agreement to replace the agreement that expired in December 2010.

The labor agreement with the construction workers in UTICE terminated in January 2011. UTICE represented 10% of the Authority's employees on June 30, 2013. Negotiations were continuing at the end of fiscal year 2013.

EMPLOYEE SAFETY

Each of the Authority's directors is responsible to the Executive Director for the safety and health of the employees working within their respective directorate. Subordinate managers, supervisors, and ultimately the workers themselves share this responsibility. The Occupational Safety Division assigns the safety and health professionals and certain of the other resources needed to assist the directors in their efforts to prevent accidents and job-related illnesses. The Occupational Safety Division ensures that the Authority's workplace safety and health programs comply with relevant Federal and Commonwealth statutes and are consistent with the objectives of the Authority.

The Division's staff of 28, comprised largely of safety and health professionals, provides assistance to managers and supervisors in the day-to-day implementation of safety and health programs. Fifteen of the 28 are assigned to other electric generating facilities and regional offices. The following is a sampling of the distribution of safety and health professionals across the island. There are eight Safety and Industrial Hygiene Officers, of these one is assigned to each of five generating stations, Central Aguirre Steam, Aguirre Combined Cycle, Central Costa Sur, Central Palo Seco, and Central San Juan. Two Safety and Industrial Hygiene Officers are based in Santurce. From these office locations they provide consulting services to the Cambalache Power Plant, gas turbine sites, the hydroelectric stations as well as to the other directorates. A Health and Safety Officer is assigned in each of the seven regional Transmission and Distribution offices in Arecibo, Carolina, Ponce, San Juan, Bayamon, Caguas, and Mayagüez. One Health and Safety Officer is assigned to the Line and Substation Construction Subdivision. The Authority has a single Safety Consultant based at the Costa Sur Steam Plant who is responsible for the development and implementation of safety programs for the Authority's construction sites. The Hazard Communication Section provides initial and refresher training in hazardous waste operations and emergency response (HAZWOPER) to employees assigned throughout the Authority. The training covers hazard recognition, hazard communication, and the use of personal protective equipment. Additional resources include an attorney who assists the Authority in responding to Puerto Rico OSHA (PR OSHA) citations, provides guidance with respect to safety laws,

and who chairs the Central Health and Safety Committee with UTIER.

The Division has a performance recognition program for units and Directorates whose employees work in a high risk environment and a second recognition program for those working in office environments where there is less risk of a work related injury or illness.

During the past year the Authority conducted 511 training sessions for 6,637 employees in 32 different subject areas. The Authority's supervisory training focused on the importance of conducting and recording job briefings to ensure that subordinates fully understood the exposures they might encounter in the performance of their tasks, the personal protective equipment and actions necessary to safely complete the assigned task. In addition the supervisory training programs increased the awareness of the direct and indirect costs of accidents and illnesses and their effect on the Authority's cost of doing business.

In calendar year 2013, the Authority reported to PR OSHA that its employees worked a total of 14,465,221 hours and sustained 1,355 incidents of work related injury or illness that were recordable in accordance with OSHA's requirements. There were twenty five serious accidents during the year. Since 2004 the Authority and other Puerto Rican public corporations have been subject to financial penalties, in the same manner as private corporations, for violations of OSHA regulations. The Authority's managers and supervisors are routinely briefed annually on the change in the OSHA penalty provisions. In calendar year 2013, the Authority was cited sixteen times for violating OSHA regulations. PR OSHA proposed fines totaling $41,975 for eight of the citations; the Authority paid $8,500 in settlement of these citations. The proposed fines associated with the eight remaining citations from fiscal year 2013 total more than $65,000 and are being contested by the Authority.

The employees of the Occupational Health Division, within the Human Resources and Labor Affairs Directorate, are responsible for providing first aid, medical treatment, training, and administrative services to employees from the reported onset of a work related injury or illness until the employee returns to work, is reassigned, or reclassified. They provide a range of health related activities and training programs. An employee's initial contact with this division is frequently at one of the eight dispensaries that are staffed with registered nurses. The dispensaries are located at the Authority's main office in Santurce, in regional offices in Monacillos, Caguas, and Ponce and at the steam electric plants in Aguirre, Costa Sur, Palo Seco, and San Juan. In most cases, however, the first aid and treatment provided by the Authority's registered nurses were for a condition that was classified as non-occupational.

Following a work related injury or illness almost all employees are referred from the Authority's dispensary or a first aid facility to one of the Commonwealth's treatment clinics, which are a part of the Corporación del Fondo del Seguro del Estado (CFSE) or Fondo for short. The physicians and medical staff employed by Fondo provide the medical care required for the Authority's employees following a work related injury or illness and determine when the employee is capable of returning to work. A long-term goal of the Authority has been to obtain the cooperation of Fondo's representatives to expedite the care being provided to their injured or ill employees.

Since 1995 the Authority has had a random drug-testing program, which has been implemented in steps. The random drug testing program applies to employees in safety sensitive positions, which constitutes more than 60% of its workforce. During the past year approximately 25% of these employees were randomly tested. Employees who test positive and are referred to a three month long treatment program, where they received treatment and counseling. Repeat violators are also referred to treatment, however, the Authority's policy is an employee who tests positive for drugs three times may be terminated. The Authority also administers drug tests to all candidates for employment.

LEGAL AFFAIRS

The thirty attorneys of the Legal Affairs Directorate's are responsible for a wide range of contract and litigation related activities. The following discussion summarizes the status of a number of the issues that the Authority litigated during fiscal year 2013.

During the past fiscal year the breach of contract litigation between Abengoa, Puerto Rico, S.E. and the Authority continued in discovery in Superior Court, Court of First Instance in Puerto Rico. The suit dates to an action in May 2000 when Abengoa, the prime contractor for the construction of two combined cycle units at San Juan Steam Plant, terminated their contract and left the construction jobsite; Abengoa alleges $18 million in losses and claimed as one basis that the Authority had not obtained the required permits from the EPA that were necessary for the construction to proceed. The Authority filed a counter claim for breach of con-

tract and subsequently completed construction of the units with another firm. The units went into commercial operation in October 2008. The Authority in 2011 estimated their losses as a result of Abengoa's alleged breach of contract to be approximately $250 million. In October 2007 the lawsuit was certified as complex litigation by the Superior Court of San Juan and a specially appointed arbitrator was named to assist both parties in reaching a settlement. Subsequent failure of the arbitration process moved the litigation to trial where the case will be adjudicated in two phases: liability, and wrongful termination and damages. A Status hearing was scheduled to be held in July 2013; it is anticipated that both parties will submit a Joint Pretrial Report in November 2013.

As part of the settlement in 2007 of the litigation over the Contributions in Lieu of Taxes, CILT, the Authority agreed to perform certain infrastructure projects for the municipalities involved in the litigation. Work was continuing during the past fiscal year.

The Authority filed suit in Puerto Rican Court seven years ago against the Brazilian manufacturer and the manufacturer's Puerto Rico agent over the failure of the more than 6,000 batteries in the Sabana Llana Battery Energy Storage System, BESS. The Authority claimed damages of more than $18 million against the co-defendants, the manufacturer and their Puerto Rican partner. During fiscal year 2010 the Brazilian battery manufacturer declared bankruptcy. The Authority continued to litigate this case against the Puerto Rican partner. The bonding company standing behind the Brazilian manufacturer and the Puerto Rican partner subsequently failed during 2011. The Authority has been advised that recovery of more than $500,000 from the bonding company is unlikely. The Authority expects to settle this litigation during fiscal year 2014 and dispose of the batteries for salvage value.

The Authority has increased its efforts to eliminate the theft of electricity. Electricity theft is occurring across client classes, throughout the Commonwealth and has been identified as having a material impact on the Authority's operations. During fiscal year 2013 the Authority increased its focus on smart grid technology to identify and discourage the theft of electricity. Continued implementation of upgraded meters and new smart data technology systems will allow the Authority to identify usage patterns and system disturbances consistent with electric energy theft. The upgraded meters can remotely disconnect service, when appropriate. The Authority plans to install approximately 60,000 upgraded meters in fiscal 2014 bringing the total to 230,000. Larger Commercial and Industrial theft will be investigated and adjudicated by the Puerto Rico Department of Justice, reducing the need and expense of administrative law judges in the recovery process. During fiscal year 2013 the Authority identified $19.1 million in theft related lost revenue, of which, approximately $5.0 million was recovered. The Authority's financials shows an annual recovery of $30 million in theft related lost revenues for each of the fiscal years 2014 through 2018.

On August 23, 2007 Power Technologies Corp filed suit against the Authority over the Authority's decision not to proceed with a project to construct an electric generating plant in the Mayagüez area. Power Technologies Corp alleges that the project was cancelled without justification; they are seeking recovery of damages of more than $51 million. The case was withdrawn by Power Technologies when both parties agreed to negotiate.

The Caribbean Petroleum Corporation's (CAPECO), fuel storage depot in Bayamon caught fire in October 2009. The Authority had residual fuel oil and distillate stored at the depot. The fire was extensive; it shut down the depot and caused some amount of air and water contamination to the adjacent area. The Authority and numerous other parties have been named in suits filed against CAPECO. Early in fiscal year 2011 CAPECO filed for bankruptcy protection, staying the suits against it. In December 2010 CAPECO sold its assets to Puma Energy Caribe who commenced the reconstruction of the damaged facility and environmental remediation. At the end of fiscal year 2013 the suit against the Authority and others continued in the discovery stage of what could be a lengthy process but one not material to the Authority.

Following a heavy rainstorm in 2009 there was a mudslide that destroyed and damaged a number of homes built by squatters on steep hillsides in the Ponce area. The mudslide occurred in an area where there were Authority, PRASA, and other utility structures. Six plaintiffs filed suit against the Authority and the other utilities, claiming $19.5 million in damages. Those bringing suit allege that their losses were the result of soil instability that resulted from the installation of utilities, such as tower foundations, underground services, utility poles and towers. The Authority alleges that the

utility installations predated the construction of the homes. The case was stayed by the court following bankruptcy proceedings for PRASA's insurer after which the Authority will continue with its defense. This suit is not likely to be resolved in fiscal year 2014.

In 2005 fifty-five former workers, all of whom have a condition that can be associated with asbestos exposure and who were employed by the Authority from 1960 to 2000, filed suit against the Authority. They former workers claim they were exposed to asbestos during their employ and that the Authority did not provide adequate protection as required by federal and local laws. The plaintiffs are calming $320 million damages for health related illnesses. The Authority has filed a motion for dismissal claiming immunity from suit since those bringing the suit were former employees and were covered by workman's compensation. Discovery is scheduled to end in fiscal year 2014.

SUPPLEMENTARY INFORMATION

EXECUTIVE DIRECTOR CHANGES

In January 2013 Ing Josué A. Colón Ortiz resigned from the Authority after serving as the Acting Executive Director since June 2012. Prior to his appointment Ing Colón was the Director of Generation; his career with the Authority spanned 24 years, from design and maintenance engineering to management of production plant operations.

Following Ing Colón's resignation, Ing Juan Alicea Flores was appointed Executive Director later that month. Ing Alicea has 30 years experience with the Authority. During his tenure with the Authority he has held numerous senior management positions including Acting Executive Director, Director of Planning & Environmental Protection, General Power Plant Manager at the Palo Seco Steam Power Plant, Maintenance Department Head and Operations Department Head of the Aguirre Power Plant and Senior Shift Engineer. Ing Alicea graduated with a degree in Mechanical Engineering from the Mayaguez Campus of the University of Puerto Rico.

In February 2013 the Authority's Governing Board appointed Ing Roberto Garay González to the newly reopened the post of Vice Executive Director. Ing Garay has 25 years of experience at the Authority during which he has held senior positions such as Transmission and Distribution Technical Operations Director, and Transmission and Distribution Engineer. Ing Garay is an electrical engineer and has a Master Degree in Engineering Management.

PREPA SUBSIDIARIES

The Authority' organization includes two component units—Puerto Rico Irrigation Systems and PREPA Holdings LLC. Both were active at the end of fiscal year 2013.

The Puerto Rico Irrigation System operates various legacy portions of irrigation systems throughout the island. The condensed financial statement for Irrigation Systems as of June 30, 2013 showed $28.0 million in total assets and the annual revenue loss of $4.6 million, based on operating revenues of $6.9 million and operating expenses of $11.5 million. In addition, the Puerto Rico Irrigation System transferred $6.0 million to the Commonwealth government.

PREPA Holdings, LLC is a subsidiary of the Authority that was created as the holding company for the

Authority's four other subsidiaries: PREPA Networks, LLC (merged from and PREPA.NET); InterAmerican Energy Sources, LLC; PREPA Utilities, LLC; and PREPA Oil & Gas, LLC. The latter two were not operating in fiscal year 2013.

Based on the independent consolidated financial statements prepared for PREPA Holdings, LLC, at the end of fiscal year 2013 the total consolidated assets of PREPA Holdings were $46.5 million and its consolidated liabilities were $29.6 million. PREPA Holdings' operating revenues were $14.5 million and its operating expenses were $8.2 million; this resulted in an operating income of $4.1 million after interest and the transfer to the Commonwealth government of $2.0 million. The consolidated operating revenues in fiscal year 2013 were up $0.9 million over the previous year primarily from the amounts received from the local telecommunications company for the joint pole attachments in the three prior fiscal years through 2012.

In 2000 the Authority began the acquisition of a fiber optic cable system to modernize the Authority's internal communication systems and thereby provide faster and more secure data transmission for operations, load management, system protection, and security. In order to meet its optical fiber cable requirements, the Authority entered into a long-term agreement with Puerto Rico Information Networks, Inc. (PRIN) a private, independent, non-profit corporation incorporated in Puerto Rico. Under the agreement, PRIN designed and built a fiber optic cable system that was installed on the Authority's rights-of-way (mainly its transmission lines). The fiber-optic cable is an integral part of the overhead ground wires which protect transmission lines from lightning strikes. When completed in August 2002, title to the system was transferred to the Authority.

The Authority financed its acquisition of the fiber optic system from PRIN by selling $43.7 million of Subordinate Obligations in October 2002. In June 2005 the Authority created PREPA Networks, LLC (PREPA.Net) to replace PRIN and market the excess communication capacity of the fiber optic network. PREPA.Net owns, operates and maintains the fiberoptic network that offers next generation telecommunications (NGT) service to carriers, internet service providers (ISPs), and large enterprises. PREPA.net's network has optical technology that is used by service providers to communicate with submarine cable landing stations, wireless network towers and island wide locations.

During fiscal year 2008 PREPA.net acquired Ultracom, one of three submarine cable firms on the island, to obtain international fiber optic cable capacity and satellite teleport facilities. The acquisition was financed with a term loan of $10.1 million due in February 2023. The balance of the loan as of the end of fiscal year 2013 was $8.1 million.

In November 2011 PREPA.NET entered into a 10 year Indefeasible Right to Use purchase agreement with PRASA in the amount of $13.7 million. The agreement allows PRASA an Indefeasible Right to Use (IRU) for the fiber optic communication network.

Also in fiscal year 2012 PREPA.net acquired property in Isla Verde for the development of a facility to support its telecommunications business; the facility is scheduled for completion in fiscal year 2014.

On March 12, 2012 PREPA Networks, Corporation and PREPA .NET merged to form PREPA Holdings, LLC.

Also in March 2012, PREPA holdings entered into an 18 year IRU sale agreement with Cable and Wireless of Panama, S.A. (CWP) for the amount of $2.3 million. The agreement grants PREPA Holdings an IRU for the fiber optic communication network owned by CWP.

During fiscal year 2013 the following subsidiaries were not in operation:

PREPA Utilities was formed to financially participate in, develop, construct and operate industrial projects and other related infrastructure to improve the electric infrastructure of the Authority.

PREPA Oil & Gas was established to provide a mechanism for the Authority to participate in a wide range of financial, commercial and operational projects for fuel supply and infrastructure.

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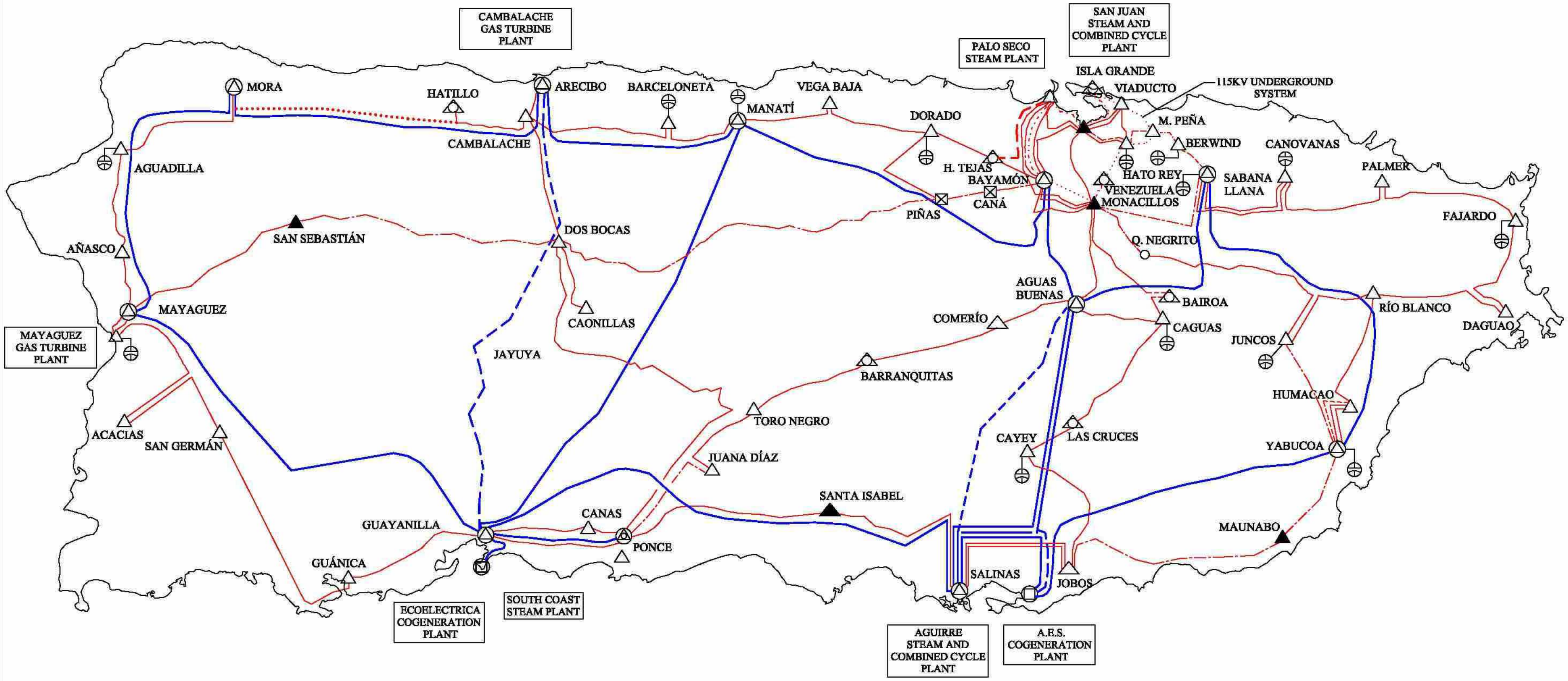
PREPA'S TRANSMISSION SYSTEM
2018



LEGEND:

230 KV LINE
NEW 230 KV LINE
RECONSTRUCTED 230 KV LINE
115 KV LINE
NEW 115 KV LINE
RECONSTRUCTED115 KV LINE
115 KV UNDERGROUND LINE
115 KV CAPACITOR BANK

230/115 KV TRANSFORMER
NEW 230/115 KV TRANSFORMER
230/115 KV TRANSFORMER INCREASE CAPACITY
115/38 KV TRANSFORMER
NEW 115/38 KV TRANSFORMER
115/38 KV TRANSFORMER INCREASE CAPACITY
230 KV SWITCHYARD
NEW 230 KV SWITCHYARD
NEW 115 KV SWITCHYARD

PLANNED TRANSMISSION SYSTEM IMPROVEMENTS THRU FY 2018

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APPENDICES

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APPENDIX I

INTERMEDIATE-TERM FINANCIAL PLANNING FORECAST

	Actual		Forecast									
	2013		2014		2015		2016		2017		2018	
	Amount	Increase %	Amount	Increase %	Amount	Increase %	Amount	Increase %	Amount	Increase %	Amount	Increase %
kWh SALES (000)												
Residential	6,655,596	1.46	6,929,613	4.12	6,941,706	0.17	7,022,449	1.16	7,138,391	1.65	7,276,068	1.93
Commercial	8,635,165	4.04	8,591,133	(0.51)	8,668,240	0.90	8,799,775	1.52	8,961,607	1.84	9,143,746	2.03
Industrial	2,578,386	(7.20)	2,337,478	(9.34)	2,317,024	(0.88)	2,312,026	(0.22)	2,316,079	0.18	2,329,938	0.60
Public Lighting	268,322	(32.51)	249,796	(6.90)	249,796	0.00	250,480	0.27	249,796	(0.27)	249,796	0.00
Agricultural	27,277	0.17	26,633	(2.36)	26,633	0.00	26,706	0.27	26,633	(0.27)	26,633	0.00
Others	56,436	14.08	64,377	14.07	64,377	0.00	64,554	0.27	64,377	(0.27)	64,377	0.00
TOTAL	18,221,182	0.60	18,199,030	(0.12)	18,267,776	0.38	18,475,990	1.14	18,756,883	1.52	19,090,558	1.78
CUSTOMERS (12 month average)												
Residential	1,353,550	0.98	1,368,861	1.13	1,383,721	1.09	1,398,580	1.07	1,413,440	1.06	1,428,300	1.05
Commercial	126,735	(1.44)	129,144	1.90	131,535	1.85	132,496	0.73	133,458	0.73	134,420	0.72
Industrial	709	(3.27)	681	(3.95)	654	(3.96)	628	(3.98)	603	(3.98)	579	(3.98)
Public Lighting	2,926	22.12	2,924	(0.07)	2,924	0.00	2,924	0.00	2,924	0.00	2,924	0.00
Agricultural	1,227	(3.23)	1,228	0.08	1,228	0.00	1,228	0.00	1,228	0.00	1,228	0.00
Others	3	50.00	3	0.00	3	0.00	3	0.00	3	0.00	3	0.00
TOTAL	1,485,150	0.80	1,502,841	1.19	1,520,065	1.15	1,535,859	1.04	1,551,656	1.03	1,567,454	1.02
kWh PER CUSTOMER												
Residential	4,917	0.48	5,062	2.95	5,017	(0.90)	5,021	0.09	5,050	0.58	5,094	0.87
Commercial	68,136	5.56	66,524	(2.37)	65,901	(0.94)	66,415	0.78	67,149	1.10	68,024	1.30
Industrial	3,636,652	(4.06)	3,432,420	(5.62)	3,542,850	3.22	3,681,570	3.92	3,840,927	4.33	4,024,073	4.77
Public Lighting	91,703	(44.74)	85,430	(6.84)	85,430	0.00	85,663	0.27	85,430	(0.27)	85,430	0.00
Agricultural	22,231	3.52	21,688	(2.44)	21,688	0.00	21,748	0.27	21,688	(0.27)	21,688	0.00
Others	18,812,000	(23.95)	21,459,000	14.07	21,459,000	0.00	21,518,000	0.27	21,459,000	(0.27)	21,459,000	0.00
TOTAL	12,269	(0.20)	12,110		12,018		12,030		12,088		12,179	
BASE REVENUE ($000)												
Residential	$ 341,774	1.28	$ 348,110	1.85	$ 349,004	0.26	$ 353,046	1.16	$ 358,762	1.62	$ 365,512	1.88
Commercial	600,768	5.67	601,732	0.16	607,132	0.90	616,345	1.52	627,680	1.84	640,437	2.03
Industrial	115,896	(3.83)	106,733	(7.91)	105,799	(0.88)	105,571	(0.22)	105,756	0.18	106,389	0.60
Public Lighting	51,762	4.69	48,509	(6.28)	48,509	0.00	48,642	0.27	48,509	(0.27)	48,509	0.00
Agricultural	1,677	0.12	1,659	(1.07)	1,659	0.00	1,663	0.24	1,659	(0.24)	1,659	0.00
Others	2,175	1.87	3,047	40.09	3,047	0.00	3,056	0.30	3,047	(0.29)	3,047	0.00
TOTAL	$ 1,114,052	3.18	$ 1,109,790	(0.38)	$ 1,115,150	0.48	$ 1,128,323	1.18	$ 1,145,413	1.51	$ 1,165,553	1.76
FUEL OIL ADJUSTMENT ($000)												
Residential	$ 1,010,924	(10.90)	$ 942,633	(6.76)	$ 920,260	(2.37)	$ 894,815	(2.76)	$ 895,305	0.05	$ 847,674	(5.32)
Commercial	1,411,558	(8.03)	1,143,691	(18.98)	1,125,256	(1.61)	1,097,972	(2.42)	1,100,607	0.24	1,043,116	(5.22)
Industrial	378,049	(16.23)	285,209	(24.56)	275,801	(3.30)	264,519	(4.09)	260,821	(1.40)	243,723	(6.56)
Public Lighting	47,981	(5.67)	35,226	(26.58)	34,326	(2.55)	33,084	(3.62)	32,475	(1.84)	30,165	(7.11)
Agricultural	4,580	(13.99)	3,755	(18.01)	3,662	(2.48)	3,529	(3.63)	3,465	(1.81)	3,218	(7.13)
Others	8,874	9.11	7,809	(12.00)	7,610	(2.55)	7,336	(3.60)	7,200	(1.85)	6,688	(7.11)
TOTAL	$ 2,861,966	(10.15)	$ 2,418,323	(15.50)	$ 2,366,915	(2.13)	$ 2,301,255	(2.77)	$ 2,299,873	(0.06)	$ 2,174,584	(5.45)
PURCHASED POWER ($000)												
Residential	$ 314,443	10.37	$ 352,179	12.00	$ 394,553	12.03	$ 407,508	3.28	$ 421,512	3.44	$ 436,022	3.44
Commercial	405,155	12.44	428,278	5.71	482,444	12.65	500,030	3.65	518,169	3.63	536,552	3.55
Industrial	108,317	1.94	106,938	(1.27)	118,247	10.58	120,465	1.88	122,796	1.94	125,365	2.09
Public Lighting	13,794	15.31	13,194	(4.35)	14,717	11.54	15,066	2.37	15,289	1.48	15,516	1.48
Agricultural	1,328	7.01	1,410	6.17	1,570	11.35	1,607	2.36	1,631	1.49	1,655	1.47
Others	2,293	22.69	2,920	27.34	3,263	11.75	3,340	2.36	3,390	1.50	3,440	1.47
TOTAL	$ 845,330	10.28	$ 904,919	7.05	$ 1,014,794	12.14	$ 1,048,016	3.27	$ 1,082,787	3.32	$ 1,118,550	3.30
REVENUES ($000)-incl. adj. charge												
Residential	$ 1,667,141	(5.11)	$ 1,642,921	(1.45)	$ 1,663,817	1.27	$ 1,655,368	(0.51)	$ 1,675,579	1.22	$ 1,649,208	(1.57)
Commercial	2,417,481	(1.88)	$ 2,173,702	(10.08)	2,214,831	1.89	2,214,347	(0.02)	2,246,456	1.45	2,220,105	(1.17)
Industrial	602,262	(11.18)	498,879	(17.17)	499,847	0.19	490,555	(1.86)	489,373	(0.24)	475,477	(2.84)
Public Lighting	113,537	1.13	96,930	(14.63)	97,552	0.64	96,792	(0.78)	96,273	(0.54)	94,190	(2.16)
Agricultural	7,585	(7.96)	6,824	(10.03)	6,891	0.98	6,799	(1.34)	6,755	(0.65)	6,532	(3.30)
Others	13,342	9.93	13,776	3.25	13,920	1.05	13,731	(1.36)	13,637	(0.68)	13,175	(3.39)
TOTAL	$ 4,821,348	(4.18)	$ 4,433,032	(8.05)	$ 4,496,858	1.44	$ 4,477,592	(0.43)	$ 4,528,073	1.13	$ 4,458,687	(1.53)

APPENDIX II
INCOME STATEMENT

	Actual[1]	Forecast				
	2013	2014	2015	2016	2017	2018
REVENUES						
Revenues from Appendix I	$ 4,821,348,190	$ 4,433,032,000	$ 4,496,858,000	$ 4,477,592,000	$ 4,528,073,000	$ 4,458,687,000
Add'l Revenues from Theft Recovery	-	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000
From Sales of Electricity	4,821,348,190	4,463,032,000	4,526,858,000	4,507,592,000	4,558,073,000	4,488,687,000
Other Operating Revenue-Net	30,166,264	-	-	-	-	-
Total Operating Revenue	4,851,514,454	4,463,032,000	4,526,858,000	4,507,592,000	4,558,073,000	4,488,687,000
Other Income-Net	(698,076)	31,179,000	31,179,000	31,179,000	31,179,000	31,179,000
Total Revenues	$ 4,850,816,378	$ 4,494,211,000	$ 4,558,037,000	$ 4,538,771,000	$ 4,589,252,000	$ 4,519,866,000
CURRENT EXPENSES						
Operating Expenses	$ 4,125,389,640	$ 3,700,008,000	$ 3,734,895,000	$ 3,716,576,000	$ 3,749,204,000	$ 3,671,427,000
Miscellaneous Interest and Other	-	-	-	-	-	-
Total Current Expenses	4,125,389,640	3,700,008,000	3,734,895,000	3,716,576,000	3,749,204,000	3,671,427,000
Balance to Revenue Fund	$ 725,426,738	$ 794,203,000	$ 823,142,000	$ 822,195,000	$ 840,048,000	$ 848,439,000
1974 SINKING FUND						
Interest on Bonds	$ 332,503,272	$ 358,463,000	$ 364,096,000	$ 368,753,000	$ 388,867,000	$ 376,697,000
Bond Redemption	194,920,000	204,305,000	214,410,000	224,035,000	237,365,000	249,535,000
Reserve Account	-	-	-	-	-	-
Total Sinking Fund Payments[2]	$ 527,423,272	$ 562,768,000	$ 578,506,000	$ 592,788,000	$ 626,232,000	$ 626,232,000
Balance	$ 198,003,466	$ 231,435,000	$ 244,636,000	$ 229,407,000	$ 213,816,000	$ 222,207,000
TRANSFERS						
Reserve Maintenance Fund	-	-	-	-	-	-
Self Insurance Fund	-	-	-	-	-	-
1974 Capital Improvement Fund	16,986,499	22,677,000	31,321,000	12,920,000	12,920,000	12,920,000
Interest on Notes	457,798	7,731,000	7,552,000	7,552,000	7,552,000	7,552,000
Total	$ 17,444,297	$ 30,408,000	$ 38,873,000	$ 20,472,000	$ 20,472,000	$ 20,472,000
Balance	$ 180,559,169	$ 201,027,000	$ 205,763,000	$ 208,935,000	$ 193,344,000	$ 201,735,000
Contributions in Lieu of Taxes and Other	180,559,169	201,027,000	205,763,000	208,935,000	193,344,000	201,735,000
Balance	$ -	$ -	$ -	$ -	$ -	$ -

1. Audited
2. Principal and Interest requirements are net of capitalized interest from previous bond issues.

APPENDIX III
DETAIL OF OPERATING and MAINTENANCE EXPENSES

	Actual[1]	Forecast				
	2013	2014	2015	2016	2017	2018
OPERATION						
Thermal and Gas Production						
Fuel Expense						
Fuel[2]	$ 2,603,577,000	$ 2,145,911,000	$ 2,100,801,000	$ 2,044,913,000	$ 2,044,304,000	$ 1,934,695,000
Purchased Power	755,686,000	805,414,000	903,208,000	932,776,000	963,724,000	995,556,000
Other Production Costs	69,718,000	63,943,000	56,739,000	57,361,000	57,538,000	57,538,000
Hydroelectric Plant Production	1,937,000	1,756,000	1,558,000	1,575,000	1,580,000	1,580,000
Transmission	19,272,000	26,132,000	24,427,000	24,695,000	24,771,000	24,771,000
Distribution	153,046,000	132,599,000	123,950,000	125,306,000	125,695,000	125,695,000
Client Accounting and Collection	116,351,000	115,370,000	111,521,000	112,742,000	113,091,000	113,091,000
Administrative and General	191,913,000	175,510,000	187,797,000	189,851,000	190,440,000	190,440,000
Total Operation	$ 3,911,500,000	$ 3,466,635,000	$ 3,510,001,000	$ 3,489,219,000	$ 3,521,143,000	$ 3,443,366,000
MAINTENANCE						
Thermal and Gas Production	$ 99,355,000	$ 108,694,187	$ 104,745,067	$ 105,892,216	$ 106,220,107	$ 106,220,107
Hydroelectric Plant	2,860,000	3,629,869	3,497,987	3,536,296	3,547,246	3,547,246
Transmission	30,058,000	17,437,081	16,803,550	16,987,580	17,040,181	17,040,181
Distribution	74,716,000	94,850,155	91,404,022	92,405,063	92,691,191	92,691,191
General Plant	6,901,000	8,761,708	8,443,374	8,535,845	8,562,275	8,562,275
Total Maintenance	$ 213,890,000	$ 233,373,000	$ 224,894,000	$ 227,357,000	$ 228,061,000	$ 228,061,000
TOTAL O & M	$ 4,125,390,000	$ 3,700,008,000	$ 3,734,895,000	$ 3,716,576,000	$ 3,749,204,000	$ 3,671,427,000

1. Audited
2. Projections excludes interest, transportation and handling charges

APPENDIX IV

ANNUAL NET GENERATION, FUEL CONSUMPTION, FUEL and PURCHASED POWER COSTS

	Actual	Forecast				
	2013	2014	2015	2016	2017	2018
AGUIRRE STEAM PLANT						
Net MWh-Generated	4,226,411	4,353,000	4,439,000	5,078,000	4,823,000	4,989,000
Barrels of Fuel Oil Used	7,087,884	6,954,000	7,209,000	8,757,000	8,288,000	8,589,000
MBTUx1000	44,654	43,810	44,870	51,030	48,292	50,046
kWh Per Barrel	596	626	616	580	582	581
Cost of Fuel	$ 800,803,249	$ 671,600,000	$ 669,920,000	$ 678,072,934	$ 633,956,000	$ 630,726,567
Cost of Fuel Per Barrel	$ 112.98	$ 96.58	$ 92.93	$ 77.43	$ 76.49	$ 73.43
$/Mbtu	$ 17.93	$ 15.33	$ 14.93	$ 13.29	$ 13.13	$ 12.60
COSTA SUR STEAM PLANT						
Net MWh-Generated	3,120,018	4,752,000	4,778,000	3,839,000	3,571,000	3,226,000
Barrels of Fuel Oil Used or Equivlent	5,528,530	8,459,000	8,534,000	6,908,000	6,420,000	5,801,000
MBTUx1000	34,830	50,285	50,756	41,142	38,191	34,480
kWh Per Barrel	564	562	560	556	556	556
Cost of Fuel	$ 521,197,048	$ 676,126,000	$ 691,105,000	$ 567,905,000	$ 525,286,000	$ 465,395,000
Cost of Fuel Per Barrel	$ 94.27	$ 79.93	$ 80.98	$ 82.21	$ 81.82	$ 80.23
$/Mbtu	$ 14.96	$ 13.45	$ 13.62	$ 13.80	$ 13.75	$ 13.50
PALO SECO STEAM PLANT						
Net MWh-Generated	2,689,532	2,016,000	1,785,000	1,992,000	2,089,000	2,028,000
Barrels of Fuel Oil Used or Equivlent	4,575,037	3,324,000	2,943,000	3,286,000	3,511,000	3,617,000
MBTUx1000	28,823	20,936	18,540	20,698	21,702	21,075
kWh Per Barrel	588	606	607	606	595	561
Cost of Fuel	$ 511,036,274	$ 319,444,000	$ 284,424,000	$ 318,402,000	$ 335,828,000	$ 316,710,984
Cost of Fuel Per Barrel	$ 111.70	$ 96.10	$ 96.64	$ 96.90	$ 95.65	$ 87.56
$/Mbtu	$ 17.73	$ 15.26	$ 15.34	$ 15.38	$ 15.47	$ 15.03
SAN JUAN STEAM PLANT						
Net MWh-Generated	2,002,269	998,000	640,000	716,000	778,000	627,000
Barrels of Fuel Oil Used or Equivlent	3,616,511	1,808,000	1,161,000	1,301,000	1,436,000	1,195,000
MBTUx1000	22,784	11,393	7,316	8,199	8,904	7,177
kWh Per Barrel	554	552	551	550	542	525
Cost of Fuel	$ 404,852,726	$ 174,765,000	$ 110,134,000	$ 125,714,000	$ 138,864,000	$ 110,041,000
Cost of Fuel Per Barrel	$ 111.95	$ 96.66	$ 94.86	$ 96.63	$ 96.70	$ 92.08
$/Mbtu	$ 17.77	$ 15.34	$ 15.05	$ 15.33	$ 15.60	$ 15.33
AGUIRRE COMBINED-CYCLE UNITS						
Net MWh-Generated	309,354	226,000	220,000	618,000	922,000	700,000
Barrels of Fuel Oil or Equivalent	595,728	397,000	387,000	1,063,000	1,580,000	1,206,000
MBTUx1000	3,753	2,305	2,248	6,195	9,208	7,030
kWh Per Barrel (or equivalent)	519	569	568	581	584	580
Cost of Fuel	$ 82,931,254	$ 56,069,000	$ 46,037,000	$ 81,118,376	$ 119,958,059	$ 88,873,042
Cost of Fuel Per Barrel	$ 139.21	$ 141.23	$ 118.96	$ 76.31	$ 75.92	$ 73.69
$/Mbtu	$ 22.10	$ 24.32	$ 20.48	$ 13.09	$ 13.03	$ 12.64
COMBUSTION-TURBINES & DIESELS						
Net MWh-Generated	11,439	1,000	1,000	1,000	1,000	1,000
Barrels of Fuel Oil Used	31,862	1,588	1,494	2,045	2,217	2,037
MBTUx1000	201	9	9	12	13	12
kWh Per Barrel	359	630	669	489	451	491
Cost of Fuel	$ 4,424,965	$ 222,565	$ 210,428	$ 295,774	$ 331,558	$ 314,000
Cost of Fuel Per Barrel	$ 138.88	$ 140.15	$ 140.85	$ 144.63	$ 149.55	$ 154.15
$/Mbtu	$ 22.04	$ 24.73	$ 23.38	$ 24.65	$ 25.50	$ 26.17
CAMBALACHE						
Net MWh-Generated	62,236	5,000	6,000	3,000	5,000	3,000
Barrels of Fuel Oil or Equivalent	128,558	11,587	12,876	6,375	11,205	5,921
MBTUx1000	810	67	75	37	65	34
kWh Per Barrel	484	432	466	456	446	507
Cost of Fuel[3]	$ 18,387,724	$ 1,611,000	$ 1,784,000	$ 905,000	$ 1,668,000	$ 900,000
Cost of Fuel Per Barrel	$ 143.03	$ 139.04	$ 138.55	$ 141.96	$ 148.86	$ 152.00
$/Mbtu	$ 22.70	$ 24.04	$ 23.79	$ 24.46	$ 25.66	$ 26.47
MAYAGUEZ TURBINES						
Net MWh-Generated	110,179	104,000	56,000	20,000	25,000	22,000
Barrels of Fuel Oil or Equivalent	201,497	173,752	94,811	33,483	41,790	36,453
MBTUx1000	1,269	174	95	33	42	36
kWh Per Barrel	547	599	591	597	598	604
Cost of Fuel	$ 28,238,082	$ 25,129,000	$ 13,633,000	4,912,000	6,384,000	5,740,000
Cost of Fuel Per Barrel	$ 140.14	$ 144.63	$ 143.79	$ 146.70	$ 152.76	$ 157.46
$/Mbtu	$ 22.24	$ 144.42	$ 143.51	$ 148.85	$ 152.00	$ 159.44
REPOWERED SAN JUAN UNITS. 5 & 6						
Net MWh-Generated	1,159,293	1,017,000	1,305,000	1,170,000	1,518,000	2,529,000
Barrels of Fuel Oil or Equivalent	1,654,843	1,469,000	1,910,000	1,731,000	2,166,000	3,459,000
MBTUx1000	10,426	8,522	11,083	10,046	12,596	20,158
kWh Per Barrel	701	692	683	676	701	731
Cost of Fuel	$ 231,705,894	$ 212,439,000	$ 274,401,000	255,881,000	269,704,000	301,769,774
Cost of Fuel Per Barrel	$ 140.02	$ 144.61	$ 143.67	$ 147.82	$ 124.52	$ 87.24
$/Mbtu	$ 22.22	$ 24.93	$ 24.76	$ 25.47	$ 21.41	$ 14.97

APPENDIX IV

ANNUAL NET GENERATION, FUEL CONSUMPTION, FUEL and PURCHASED POWER COSTS

	Actual	Forecast				
	2013	2014	2015	2016	2017	2018
Continued from previous page						
TOTAL THERMAL *2014 MBTU*						
Net MWh-Generated	13,690,731	13,472,000	13,229,000	13,437,000	13,732,000	14,125,000
Barrels of Fuel Oil	23,420,450	22,597,927	22,253,181	23,087,903	23,456,212	23,911,411
MBTUx1000	147,550	137,501	134,992	137,392	139,013	140,048
kWh Per Barrel	585	596	594	582	585	591
Fuel Cost	$ 2,603,577,216	$ 2,137,405,565	$ 2,091,649,428	$ 2,033,205,084	$ 2,031,980,617	$ 1,920,471,367
Fuel Financing Credit Line Interest	$ 16,611,020	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000
Fuel Cost incl Credit Line Interest	$ 2,620,188,236	$ 2,152,405,565	$ 2,106,649,428	$ 2,048,205,084	$ 2,046,980,617	$ 1,935,471,367
Cost of Fuel Per Barrel	$ 111.17	$ 95.25	$ 94.67	$ 88.71	$ 87.27	$ 80.94
$/Mbtu	$ 17.65	$ 15.54	$ 15.49	$ 14.80	$ 14.62	$ 13.71
PURCHASED POWER-ECOELECTRICA						
Net MWh-Generated	3,570,315	3,724,000	3,675,000	3,698,000	3,744,000	3,741,000
Cost	$ 407,552,844	$ 358,010,577	$ 381,442,274	$ 400,162,000	$ 421,410,500	$ 443,200,215
$/MWH	$ 114.15	$ 96.14	$ 103.79	$ 108.21	$ 112.56	$ 118.47
PURCHASED POWER-AES						
Net MWh-Generated	3,513,485	3,362,521	3,362,522	3,372,499	3,362,522	3,362,522
Cost	$ 327,509,327	$ 344,813,719	$ 351,050,291	$ 359,631,000	$ 367,774,199	$ 374,660,460
$/MWH	$ 93.21	$ 102.55	$ 104.40	$ 106.64	$ 109.37	$ 111.42
PURCHASED POWER						
Net MWh-Generated	7,083,800	7,086,521	7,037,522	7,070,499	7,106,522	7,103,522
Cost	$ 735,062,171	$ 702,824,296	$ 732,492,565	$ 759,793,000	$ 789,184,699	$ 817,860,675
$/MWH	$ 103.77	$ 99.18	$ 104.08	$ 107.46	$ 111.05	$ 115.13
RENEWABLE ENERGY SOURCES						
Total Renewable Sources						
Net MWh-Generated	143,580	621,769	994,960	997,671	994,964	994,959
Cost	$ 20,623,661	$ 102,589,786	170,714,558	172,983,000	174,538,737	177,694,649
$/MWH	$ 143.64	$ 165.00	$ 171.58	$ 173.39	$ 175.42	$ 178.59
HYDROELECTRIC						
Net MWh-Generated	90,860	126,170	126,170	126,170	126,170	126,170
TOTAL (Including Hydro & PP)						
Net MWh-Generated	21,008,971	21,306,460	21,387,652	21,631,340	21,959,656	22,349,651
Cost	$ 3,359,263,048	$ 2,942,819,647	$ 2,994,856,551	$ 2,965,981,084	$ 2,995,704,053	$ 2,916,026,691

Forecast based on ABC '13 projections
Cost of fuel includes shipping and handling charges.

APPENDIX V

DEBT SERVICE COVERAGE UNDER THE 1974 TRUST AGREEMENT

Date of Issue	Series	Principal Amount After Payments and Refunding	Maximum Principal & Interest	Adjusted Net Revenues: 12 Consecutive Months Preceding Date of Issue	Adjusted Net Revenues: Percent Coverage	Average Net Revenues: 5 Years Following Current Year	Average Net Revenues: Percent Coverage
1/3/2002	JJ (Refunding)	134,095,000 [1]	415,641,309	636,368,000	153.11	746,303,000	179.55
7/2/2002	KK (Refunding)	186,790,000 [2]	415,923,000	627,086,000	150.77	746,303,000	179.43
7/2/2002	LL	98,125,000	415,923,000	627,086,000	150.77	746,303,000	179.43
10/3/2002	MM (Refunding)	61,180,000 [3]	415,918,000	630,219,000	151.52	746,303,000	179.44
8/19/2003	NN	171,525,000 [4]	442,399,978	664,780,000	150.27	728,160,000	164.59
8/26/2004	OO (Refunding)	120,470,000 [5]	442,395,314	635,751,000	143.71	711,111,000	160.74
8/26/2004	PP (Refunding)	85,850,000 [6]	442,395,314	635,751,000	143.71	711,111,000	160.74
4/4/2005	QQ (Refunding)	95,270,000	473,784,011	612,777,000	129.34	711,111,000	150.09
4/4/2005	RR	236,265,000 [7]	473,784,011	612,777,000	129.34	711,111,000	150.09
4/4/2005	SS (Refunding)	426,415,000 [8]	473,784,011	612,777,000	129.34	711,111,000	150.09
5/3/2007	TT	643,530,000	455,022,444	698,001,000	153.40	723,100,000	158.92
5/3/2007	UU (Refunding)	857,565,000 [9]	455,022,444	698,001,000	153.40	723,100,000	158.92
5/30/2007	V V (Refunding)	557,410,000	455,022,444	698,001,000	153.40	723,100,000	158.92
6/26/2008	W W	663,660,000 [10]	476,874,792	662,928,000	139.02	756,405,000	158.62
4/7/2010	XX	822,210,000	520,073,371	722,064,000	138.84	794,200,000	152.71
4/29/2010	YY (Refunding)	320,175,000	532,820,338	722,064,000	135.52	794,200,000	149.06
5/5/2010	ZZ (Refunding)	587,200,000	528,945,786	740,862,000	140.06	794,200,000	150.15
5/5/2010	AAA	363,075,000	528,945,786	740,862,000	140.06	794,200,000	150.15
5/26/2010	BBB	76,800,000	549,321,366	740,862,000	134.87	794,200,000	144.58
5/26/2010	CCC	316,920,000	549,321,366	740,862,000	134.87	794,200,000	144.58
10/14/2010	DDD (Refunding)	218,225,000	549,316,970	739,106,000	134.55	856,100,000	155.85
12/29/2010	EEE	355,730,000	563,367,710	708,449,000	125.75	856,100,000	151.96
5/1/2012	2012A	630,110,000	594,844,190	699,667,000	117.62	837,000,000	140.71
5/1/2012	2012B (Refunding)	19,890,000 [11]	594,844,190	699,667,000	117.62	837,000,000	140.71

APPENDIX V

DEBT SERVICE COVERAGE UNDER THE 1974 TRUST AGREEMENT

Continued from previous page

The total debt issued under the Trust Agreement is $17,782,028,431 which includes refunding totalling $7,872,068,473.
As of June 30, 2013, the outstanding debt under the 1974 Trust Agreement is $8,048,485,000.

The superscripted Principal Amounts in the table reflect the effects of refunding described below:

1. $690,000 refunded by Series ZZ and deducted from the original $205,065,000 Series JJ issue.
2. $7,765,000 refunded by Series SS, $19,000,000 refunded by Series ZZ and deducted from the original $401,785,000 Series KK issue.
3. $11,000,000 refunded by Series SS, $1,045,000 refunded by Series ZZ and deducted from the original $105,055,000 Series MM issue.
4. $288,590,000 refunded by Series VV; $57,190,000 refunded by Series UU and deducted from original amount $517,305,000 Series NN issue.
5. $3,535,000 refunded by Series ZZ and deducted from original $136,105,000 Series OO issue.
6. $235,000 refunded by Series ZZ and deducted from original $86,595,000 Series PP issue.
7. $273,255,000 refunded by Series VV and deducted from original $509,520,000 Series RR issue.
8. $9,190,000 refunded by Series ZZ and deducted from original $483,930,000 Series SS issue.
9. $1,885,000 refunded by Series ZZ, $434,190,000 refunded by Series AAA and deducted from original $1,300,035,000 Series UU issue.
10. $10,685,000 refunded by Series ZZ and deducted from original $697,345,000 Series WW issue.
11. $21,345,000 refunded by Series 2012B and deducted from original $515,305,000 Series II issue.

APPENDIX VI

CAPITAL EXPENDITURES

	Actual[1]	Forecast				
	2013	2014	2015	2016	2017	2018
Production Plant	$ 107,810,000	$ 96,375,000	$ 115,850,000	$ 110,365,000	$ 128,502,000	$ 124,650,000
Transmission Plant	69,661,000	66,347,000	61,262,000	66,859,000	62,613,000	72,391,000
Distribution Plant	127,926,000	99,884,000	87,532,000	88,836,000	96,112,000	92,774,000
General Land and Buildings	4,520,000	7,217,000	9,131,000	7,569,000	9,227,000	9,276,000
General Equipment	17,805,000	26,552,000	22,191,000	22,288,000	23,583,000	22,934,000
Preliminary Surveys and Investigations	(45,000)	3,625,000	4,034,000	4,083,000	4,963,000	2,975,000
SUBTOTAL	$ 327,677,000	$ 300,000,000	$ 300,000,000	$ 300,000,000	$ 325,000,000	$ 325,000,000
Construction Costs in Previous Year Reimbursed in Current Year	265,910,000	316,774,000	309,043,000	309,043,000	309,293,000	321,668,000
Construction Costs in Current Year to be Reimbursed Next Year	(316,774,000)	(309,043,000)	(309,043,000)	(309,293,000)	(321,668,000)	(327,606,000)
TOTAL FUNDS REQUIRED	$ 276,813,000	$ 307,731,000	$ 300,000,000	$ 299,750,000	$ 312,625,000	$ 319,062,000

1. Actual expenditures are net of adjustments from previous years.

APPENDIX VII
SOURCES OF FUNDS FOR CAPITAL EXPENDITURES

	Actual[1]	Forecast				
	2013	2014	2015	2016	2017	2018
FUNDS FROM BOND ISSUES AND NOTES						
REVENUE BONDS[2]						
Balance in Fund Start of Fiscal Year	$ 276,207,000	$ 50,473,000	$ 279,650,000	$ 22,471,000	$ 301,141,000	$ 10,436,000
$573.1M Series "2013A" Aug '13		500,000,000		-		
$557M Series "2015A" Aug '15			-	557,000,000		
$500M Series "2017A" Sep '17					-	500,000,000
Balance in Fund End of Fiscal Year	(50,473,000)	(279,650,000)	(22,471,000)	(301,141,000)	(10,436,000)	(213,794,000)
PAID FROM REVENUE BONDS	$ 225,734,000	$ 270,823,000	$ 257,179,000	$ 278,330,000	$ 290,705,000	$ 296,642,000
NOTES						
Notes Paid	(6,672,000)		-	-	-	-
Notes Issued-Regular Financing	-	-	-	-	-	-
PAID FROM NOTES	$ (6,672,000)	$ -	$ -	$ -	$ -	$ -
FUNDS FROM OTHER SOURCES						
Transfers from General Fund (Net)[3]	2,921,000	22,677,000	31,321,000	12,920,000	12,920,000	12,920,000
Interest earned on Construction Fund	966,000	6,500,000	4,500,000	2,000,000	2,000,000	2,000,000
Capitalized Interest on Sinking Fund	14,065,000	7,731,000	7,000,000	6,500,000	7,000,000	7,500,000
Grants and other (Principally From FEMA)[4]	39,799,000	-	-	-	-	-
PAID FROM OTHER SOURCES	57,751,000	36,908,000	42,821,000	21,420,000	21,920,000	22,420,000
GRAND TOTAL	$ 276,813,000	$ 307,731,000	$ 300,000,000	$ 299,750,000	$ 312,625,000	$ 319,062,000

1. Audited
2. Net proceeds from past bond issues
3. Net of Capital Improvement Funds less capitalized interest transferred to the General Fund.
4. Amounts available to finance the CIP from FY2009-2012 which was not transferred from the General Fund to the Construction Fund.

APPENDIX VIII
SYSTEM CAPABILITY
MW OF GENERATING CAPACITY AT THE END OF THE FISCAL YEAR

	Actual	Forecast				
	2013	2014	2015	2016	2017	2018
STEAM-ELECTRIC UNITS						
Aguirre	900	-	-	-	-	-
Costa Sur	990	-	-		-	-
CS Unit's 3 & 4				-	-	-
Palo Seco	602					
San Juan	400	-	-	-	-	-
Total	2,892	-	-	-	-	-
COMBUSTION-TURBINE UNITS						
Aguirre	42	-	-	-	-	-
Cambalache	248	-	-	-	-	-
Costa Sur	42	-	-	-	-	-
Palo Seco	126	-	-	-	-	-
Other	168	-	-	-	-	-
Total	626	-	-	-	-	-
NEW POWER PLANT						
Repowering (San Juan Units No. 5 & 6)	440	-	-	-	-	-
New Mayaguez Combustion Turbines	220	-	-			
Non-System Sources						
Cogenerators (Net)	961	-	-	-	-	-
Small Power Producers [1]	-	-	-	-	-	-
COMBINED-CYCLE UNITS						
Aguirre	592	-	-	-	-	-
DIESEL UNITS						
Culebra & Vieques	8	-	-	-	-	-
HYDROELECTRIC CAPACITY (Total)	100	-	-	-	-	-
EXISTING CAPACITY (End of Previous Fiscal Year)	5,839	5,839	5,839	5,839	5,839	5,839
CAPACITY INSTALLED	-	-	-	-	-	-
CAPACITY RETIRED	-	-	-	-	-	-
CUMULATIVE TOTAL CAPACITY (MW)	5,839	5,839	5,839	5,839	5,839	5,839
Less: PEAK LOAD (MW)*	3,265	3,304	3,339	3,377	3,438	3,492
RESERVE CAPACITY (MW)	2,574	2,535	2,500	2,462	2,401	2,347
RESERVE MARGIN (%)	79	77	75	73	70	67

* Peak load forecast from IAU Global Insight projection

[1] Energy renewable projects are recognized as energy resources; none of the projects, however, meet the criteria for firm and reliable capacity.

APPENDIX IX
DEPRECIATION EXPENSE

	Actual[1]	Forecasted				
	2013	2014	2015	2016	2017	2018
DEPRECIATION						
Steam Production Plant	$ 65,739,000	$ 67,711,170	$ 69,742,505	$ 71,834,780	$ 73,989,824	$ 76,209,518
Gas-turbine Production Plant	55,887,000	57,563,610	59,290,518	61,069,234	62,901,311	64,788,350
Hydroelectric Production Plant	1,291,000	1,329,730	1,369,622	1,410,711	1,453,032	1,496,623
Transmission Plant	52,774,000	54,357,220	55,987,937	57,667,575	59,397,602	61,179,530
Distribution Plant	119,847,000	123,442,410	127,145,683	130,960,052	134,888,854	138,935,521
General Plant[2]	47,306,000	48,725,180	50,186,935	51,692,544	53,243,320	54,840,619
Total Depreciation Expense	$ 342,844,000.00	$ 353,129,320	$ 363,723,200	$ 374,634,896	$ 385,873,943	$ 397,450,161
Amortization of Leasehold Improvements,	(407,000)					
TOTAL APPROPRIATION	$ 342,437,000	$ 353,129,320	$ 363,723,200	$ 374,634,896	$ 385,873,943	$ 397,450,161

1. Audited
2. Includes clearing accounts

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2014	2015	2016	2017	2018
PRODUCTION PLANT						
	THERMAL PRODUCTION PLANT					
100	New Generation	$ -	$ -	$ -	$ 30,000,000	$ 70,000,000
110	Renewable Energy	-	1,250,000	-	-	-
150	Fuel Handling and Storage Infrastructure	3,050,000	2,800,000	2,000,000	2,000,000	2,000,000
160	Boiler Improvements	23,150,000	34,560,000	30,500,000	32,137,000	8,000,000
165	Steam Turbines and Generators Improvements	11,400,000	16,500,000	12,500,000	17,000,000	10,400,000
170	Improvements to Balance of Steam Plant	14,150,000	9,450,000	2,765,000	2,850,000	2,500,000
173	Environmental Contamination Treatment and Removal	1,500,000	1,000,000	2,000,000	2,000,000	2,000,000
175	Pollution Control Projects	11,100,000	15,200,000	17,700,000	7,700,000	2,550,000
	Total Thermal Production Plant	$ 64,350,000	$ 80,760,000	$ 67,465,000	$ 93,687,000	$ 97,450,000
	HYDROELECTRIC PRODUCTION PLANT					
180	Hydroelectric Plant Improvements	$ 3,200,000	$ 4,000,000	$ 6,000,000	$ 8,000,000	$ 6,000,000
	Total Hydroelectricic Production Plant	$ 3,200,000	$ 4,000,000	$ 6,000,000	$ 8,000,000	$ 6,000,000
	OTHER PRODUCTION PLANT					
185	Combustion Turbine Improvements	$ 2,500,000	$ -	$ -	$ -	$ -
187	Improvements to Balance of Simple Cycle Gas Turbines	2,700,000	3,700,000	3,700,000	2,700,000	2,700,000
190	Combined Cycle Steam Turbine Improvements	5,000,000	3,300,000	3,000,000	3,915,000	-
195	Improvements to Combined Cycle Balance of Plant	2,100,000	6,700,000	10,800,000	1,500,000	1,200,000
196	Combined Cycle Gas Turbine Improvements	12,225,000	13,060,000	15,000,000	16,000,000	12,500,000
198	Combined Cycle Heat Recovery Boiler Improvements	-	500,000	2,000,000	500,000	2,800,000
199	Other Production Plant Improvements	4,300,000	3,830,000	2,400,000	2,200,000	2,000,000
	Total Other Production Plant	$ 28,825,000	$ 31,090,000	$ 36,900,000	$ 26,815,000	$ 21,200,000
	TOTAL PRODUCTION PLANT	$ 96,375,000	$ 115,850,000	$ 110,365,000	$ 128,502,000	$ 124,650,000
TRANSMISSION PLANT						
205	New 230 kV Lines	$ 8,100,000	$ -	$ -	$ 889,000	$ 5,000,000
207	New 115 kV Lines	-	-	2,752,000	6,221,000	8,861,000
210	New 38 kV Lines	1,525,000	960,000	538,000	1,602,000	646,000
215	38 kV Underground System	130,000	-	4,587,000	7,110,000	6,203,000
225	230/115 kV Transmission Centers & Capacity Increase	-	-	-	-	443,000
230	115/38 kV Transmission Centers & Capacity Increase	9,000,000	6,141,000	6,157,000	4,000,000	3,975,000
235	New 230 kV Switchyards & Expansions	-	802,000	2,293,000	444,000	1,772,000
237	New 115 kV Switchyards & Expansions	2,700,000	802,000	1,377,000	1,776,000	6,202,000
242	New 38 kV Switchyards & Expansions	4,365,000	7,404,000	6,835,000	2,221,000	4,988,000
245	New 115kV Capacitor Banks	-	641,000	-	-	-
255	Energy Management System (SCADA)	370,000	-	-	378,000	443,000
267	115 kV Line Rehabilitation	17,450,000	24,818,000	20,505,000	17,397,000	13,292,000
275	38 kV Line Rehabilitation	15,132,000	12,288,000	14,228,000	12,100,000	12,074,000

APPENDIX X

DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2014	2015	2016	2017	2018
TRANSMISSION PLANT (Cont'd.)						
280	Transmission Pole Replacement	$ 1,000,000	$ 1,800,000	$ 1,835,000	$ 1,777,000	$ 1,800,000
285	Increasing Breaker Capacity	500,000	401,000	459,000	444,000	443,000
288	Reconstruction of Grounding Mat	225,000	204,000	234,000	227,000	226,000
290	Misc. Transmission Plant Improvements—Engrg. Div.	400,000	-	-	-	-
292	Misc. Transmission Plant Improvements—Elec. System	4,500,000	4,000,000	4,000,000	5,000,000	5,000,000
294	Other Transmission Plant	950,000	1,001,000	1,059,000	1,027,000	1,023,000
	TOTAL TRANSMISSION PLANT	$ 66,347,000	$ 61,262,000	$ 66,859,000	$ 62,613,000	$ 72,391,000
DISTRIBUTION PLANT						
300	New Distribution Substations	$ 5,750,000	$ 6,411,000	$ 6,398,000	$ 7,109,000	$ 1,772,000
305	Increase Substation Capacity	-	401,000	3,211,000	2,222,000	-
310	Emergency Substations	-	-	-	955,000	975,000
315	New 13 kV Substation Feeders	7,235,000	5,805,000	5,292,000	5,798,000	6,936,000
316	4.16 kV - 8.32 kV Feeders	1,275,000	1,225,000	1,187,000	845,000	1,087,000
320	Distribution System Expansion	-	-	-	222,000	199,000
330	Line Extension to Serve New Customers	1,950,000	1,760,000	1,812,000	1,755,000	1,750,000
335	Construction of Urban Underground Lines-13.2 kV	1,090,000	1,085,000	1,260,000	1,243,000	1,197,000
337	Construction of Urban Underground Lines-4.16 - 8.32 kV	600,000	401,000	-	468,000	89,000
340	Installation of New Service Drops	912,000	960,000	1,104,000	1,200,000	1,200,000
360	Substation Rehabilization	4,750,000	5,000,000	4,500,000	5,000,000	5,000,000
363	Substation Improvements	500,000	801,000	161,000	889,000	886,000
368	Residential &Commercial Service Drop Replacements	456,000	480,000	552,000	600,000	600,000
370	Distribution System Improvements	26,633,000	26,036,000	23,660,000	26,389,000	26,095,000
374	13 kV Distribution System Improvements	4,115,000	3,408,000	4,349,000	3,459,000	3,859,000
378	Underground Line Improvements and Extensions - 13.2 kV	7,550,000	8,141,000	7,943,000	4,419,000	6,571,000
379	4.16 - 8.32 kV Underground System Improvements	9,407,000	6,822,000	8,003,000	9,199,000	9,230,000
382	Street Lighting	6,500,000	5,300,000	5,391,000	5,332,000	5,400,000
383	Line Transformers	1,215,000	1,134,000	1,115,000	1,413,000	1,276,000
385	Meters	12,286,000	4,912,000	5,470,000	9,890,000	10,890,000
390	Brakers, Sectionalizers, & Reclosers	1,475,000	862,000	987,000	955,000	953,000
392	Voltage Regulators	275,000	397,000	454,000	440,000	439,000
395	Distribution Line Capacitors	325,000	381,000	436,000	422,000	421,000
397	Line Voltage Converter	635,000	509,000	528,000	555,000	563,000
398	Distribution Automated Systems	500,000	801,000	917,000	889,000	886,000
399	Other Distribution Projects	4,450,000	4,500,000	4,106,000	4,444,000	4,500,000
	TOTAL DISTRIBUTION PLANT	$ 99,884,000	$ 87,532,000	$ 88,836,000	$ 96,112,000	$ 92,774,000

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2014	2015	2016	2017	2018
GENERAL PLANT						
	GENERAL LAND AND BUILDINGS					
400	Land and Rights-of-Way	$ 3,000,000	$ 2,404,000	$ 2,752,000	$ 2,666,000	$ 2,658,000
430	New Technical Office Construction	-	2,985,000	895,000	3,213,000	-
462	Minor Improvements to Technical Offices	600,000	721,000	711,000	422,000	532,000
468	Warehouse Improvements	350,000	781,000	1,011,000	633,000	654,000
470	Workshop Improvements	300,000	600,000	400,000	500,000	550,000
472	Improvements to Other Buildings	625,000	320,000	436,000	333,000	332,000
476	Improvements to Other Buildings & Grounds-Elect. System	500,000	-	-	-	3,000,000
478	Buildings & Grounds Improvements--Admin. Serv.	1,310,000	760,000	720,000	760,000	850,000
480	Buildings & Grounds Improvements--Cust. Serv. Offices	532,000	560,000	644,000	700,000	700,000
	TOTAL GENERAL LAND AND BUILDINGS	$ 7,217,000	$ 9,131,000	$ 7,569,000	$ 9,227,000	$ 9,276,000
	EQUIPMENT					
	OFFICE EQUIPMENT					
509	Finance	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
510	Administration Services	15,000	-	-	-	-
513	Client Service	304,000	280,000	322,000	100,000	100,000
514	Transmission & Distribution	285,000	200,000	230,000	67,000	89,000
	Total Office Equipment	$ 619,000	$ 495,000	$ 567,000	$ 182,000	$ 204,000
	COMPUTER EQUIPMENT					
520	Executive Offices	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000
521	Information Systems	2,800,000	3,600,000	4,000,000	4,000,000	4,000,000
522	Legal	25,000	20,000	25,000	30,000	30,000
523	Planning & Environmental	450,000	225,000	270,000	120,000	170,000
525	Finance	625,000	625,000	125,000	125,000	125,000
526	Administrative Services	15,000	25,000	50,000	25,000	25,000
527	Human Resources	250,000	90,000	90,000	90,000	90,000
528	Electric System	250,000	300,000	-	480,000	500,000
529	Client Service	281,000	336,000	386,000	420,000	420,000
530	Transmission & Distribution	250,000	481,000	550,000	867,000	620,000
	Total Computer Equipment	$ 4,971,000	$ 5,727,000	$ 5,521,000	$ 6,182,000	$ 6,005,000
	TRANSPORTATION EQUIPMENT					
540	Air Transportation Equipment	$ 500,000	$ 300,000	$ 350,000	$ 500,000	$ 500,000
545	Land Transportation Equipment	7,800,000	5,000,000	6,000,000	6,000,000	6,000,000
	Total Transportation Equipment	$ 8,300,000	$ 5,300,000	$ 6,350,000	$ 6,500,000	$ 6,500,000

APPENDIX X
DETAILS OF CAPITAL IMPROVEMENT PROGRAM

Budget Item Number		Estimated Expenditures by Fiscal Year 2014	2015	2016	2017	2018
GENERAL PLANT (Cont'd)						
	COMMUNICATIONS EQUIPMENT					
550	Communications Equipment-Electric System	$ 800,000	$ 1,000,000	$ 1,000,000	$ 1,000,000	$ 1,000,000
551	Communications Equipment-Client Services	38,000	40,000	46,000	50,000	50,000
553	Communications Equipment-T&D	75,000	60,000	69,000	89,000	89,000
555	Telephone and Data lines	3,250,000	3,800,000	3,250,000	3,000,000	4,500,000
	Total Communication Equipment	$ 4,163,000	$ 4,900,000	$ 4,365,000	$ 4,139,000	$ 5,639,000
	OTHER EQUIPMENT					
560	Planning and Environmental	$ 893,000	$ 1,330,000	$ 1,400,000	$ 900,000	$ 850,000
562	Engineering	4,000,000	581,000	665,000	644,000	642,000
564	Administrative Services	380,000	380,000	485,000	285,000	225,000
565	Transportation Workshop	175,000	175,000	200,000	275,000	275,000
566	Human Resources	10,000	10,000	10,000	10,000	10,000
568	Electric System	1,150,000	575,000	600,000	2,500,000	600,000
570	Client Services	391,000	412,000	474,000	350,000	350,000
572	Transmission and Distribution	1,000,000	1,806,000	1,151,000	1,116,000	1,134,000
576	Purchase Other Equipment - Corporate Security	500,000	500,000	500,000	500,000	500,000
	Total Other Equipment	$ 8,499,000	$ 5,769,000	$ 5,485,000	$ 6,580,000	$ 4,586,000
	TOTAL EQUIPMENT	$ 26,552,000	$ 22,191,000	$ 22,288,000	$ 23,583,000	$ 22,934,000
TOTAL GENERAL PLANT		$ 33,769,000	$ 31,322,000	$ 29,857,000	$ 32,810,000	$ 32,210,000
PRELIMIN. SURVEYS & INVESTIGATIONS						
600	Engineering	$ 1,975,000	$ 2,384,000	$ 2,730,000	$ 3,533,000	$ 1,750,000
605	Administrative Services	$ 50,000	$ 50,000	$ 50,000	$ 30,000	$ 25,000
610	Planning and Environmental	1,200,000	1,200,000	1,100,000	1,200,000	1,200,000
611	Renewable Energy Sources	400,000	400,000	203,000	200,000	-
	TOTAL PRELIMIN. SURVEYS & INVESTIGATIONS	$ 3,625,000	$ 4,034,000	$ 4,083,000	$ 4,963,000	$ 2,975,000
NET CAPITAL IMPROVEMENT PROGRAM		$ 300,000,000	$ 300,000,000	$ 300,000,000	$ 325,000,000	$ 325,000,000

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